ORIGINAL

OPEN MEETING ITEM

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COMMISSIONERS
MIKE GLEASON - Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

BRIAN C. McNEIL
Executive Director

ARIZONA CORPORATION COMMISSION

DATE: OCTOBER 28, 2008

DOCKET NOS: E-01933A-07-0402 and E-01933A-05-0650

TO ALL PARTIES:

Enclosed please find the recommendation of Administrative Law Judge Jane Rodda. The recommendation has been filed in the form of an Opinion and Order on:

TUCSON ELECTRIC POWER COMPANY
(RATES/AMEND DECISION NO. 62103)

Pursuant to A.A.C. R14-3-110(B), you may file exceptions to the recommendation of the Administrative Law Judge by filing an original and ten (10) copies of the exceptions with the Commission's Docket Control at the address listed below by **4:00** p.m. on or before:

NOVEMBER 6, 2008

The enclosed is NOT an order of the Commission, but a recommendation of the Administrative Law Judge to the Commissioners. Consideration of this matter has tentatively been scheduled for the Commission's Working Session and Open Meeting to be held on:

TO BE DETERMINED

For more information, you may contact Docket Control at (602) 542-3477 or the Hearing Division at (602)542-4250. For information about the Open Meeting, contact the Executive Director's Office at (602) 542-3931.

BRIAN C. McNEIL
EXECUTIVE DIRECTOR

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

MIKE GLEASON - Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

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-07-0402
IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650 DECISION NO. _____________ **OPINION AND ORDER**

DATES OF HEARING: May 12, 2008 (Public Comment)
July 9, 10, 11, 14, 15 & 16, 2008 (Hearing)

PLACE OF HEARING: Tucson, Arizona

IN ATTENDANCE: Mike Gleason, Chairman
Jeff Hatch-Miller, Commissioner
Kristin K. Mayes, Commissioner
Gary Pierce, Commissioner

ADMINISTRATIVE LAW JUDGE: Jane L. Rodda

APPEARANCES: Raymond S. Heyman, Senior Vice President and General Counsel, on behalf of Unisource Energy Corporation;

Michelle Livengood, Regulatory Counsel, on behalf of Tucson Electric Power Company;

Michael W. Patten, Roshka DeWulf & Patten, PLC, on behalf of Tucson Electric Power Company;

Daniel Pozefsky, Chief Counsel, on behalf of the Residential Utility Consumer Office;

Michael Grant, Gallagher & Kennedy, PA, on behalf of the Arizona Investment Council;

Peter Q. Nyce, Department of the Army Office of the Judge Advocate General for the Department of Defense and the Federal Executive Agencies;

C. Webb Crockett, Fennemore Craig, PC, on behalf of Arizonans for Electric Choice & Competition and Phelps Dodge Mining Company;

Lawrence V. Robertson, Jr., on behalf of Mesquite Power, LLC, Southwestern Power Group II, LLC; Bowie Power Station, LLC and Sempra Energy Solutions;

Kurt J. Boehm, Boehm, Kurtz & Lowry, on behalf of the Kroger Company;

Nicholas J. Enoch, Lubin & Enoch, PC, on behalf of the International Brotherhood of Electrical Workers Local 1116;

Timothy Hogan, Arizona Center for Law in the Public Interest on behalf of the Southwest Energy Efficiency Project;

Cynthia Zwick, pro per; and

Janet Wagner, Assistant Chief Counsel, Robin Mitchell and Nancy Scott, Staff Attorneys, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

BY THE COMMISSION:

I. Procedural Background

In 1999, Tucson Electric Power Company ("TEP" or "Company"), the Residential Utility Consumer Office ("RUCO"), Arizonans for Electric Choice and Competition ("AECC") and the Arizona Community Action Association entered into a Settlement Agreement to resolve various matters related to TEP, including TEP's application for stranded cost recovery and the establishment of unbundled tariffs (the "1999 Settlement Agreement"). The 1999 Settlement Agreement provided for the: (i) commencement of competition in TEP's service territory; (ii) establishment of unbundled rates, with a rate decrease of one percent in 1999, another rate decrease of one percent in 2000, and a rate freeze thereafter until December 31, 2008; (iii) resolution of stranded cost recovery; and (iv) settlement of TEP's Electric Competition litigation. In Decision No. 62103 (November 30, 1999) the Arizona Corporation Commission ("Commission") modified and then approved the 1999 Settlement Agreement.

On September 12, 2005, TEP filed a Motion to Amend Decision No. 62103 pursuant to A.R.S. §40-252 ("Motion to Amend"). The Motion to Amend sought resolution of the dispute over whether TEP was entitled to charge market-based rates for generation service under Decision No. 62103 and the 1999 Settlement Agreement after the expiration of the rate moratorium on December 31, 2008. Other signatories of the 1999 Settlement Agreement and the Commission's Utilities Division (Staff") opposed TEP's interpretation of the 1999 Settlement Agreement and Decision No. 62103 in light of intervening events concerning the state of retail electric competition in Arizona. The Commission conducted a hearing on the Motion to Amend from March 2, 2005 through March 9, 2005.

In the course of the hearing on the Motion to Amend, TEP presented three alternative options for determining its rates (the Market Methodology, Cost-of-Service, and a Hybrid Approach), and it became clear that the Commission could not evaluate TEP's proposals absent supporting information that would be required in a rate case. As a result, in that proceeding the parties were able to agree to a process whereby (i) TEP would file rate case information in support of each of its alternative rate proposals; (ii) all parties would preserve their rights under Decision No. 62103 and the 1999

Settlement Agreement; (iii) the termination of the Fixed Competitive Transition Charge ("Fixed CTC") would be deferred pending resolution of the rate case and subject to refund to consumers, with interest,[1] and (iv) TEP would propose implementation of Demand-Side Management ("DSM"), Time-of-Use ("TOU") and Renewable Energy Standard Tariffs ("RES tariffs"). The Commission approved the proposed process in Decision No. 69568 (May 21, 2007). As a result, the issue initially raised in TEP's Motion to Amend of how its generation rates would be determined as of January 1, 2009, was deferred to the subsequent rate case.[2]

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[1] The Fixed CTC was a portion of TEP's rates that was designated for the collection of Stranded Costs pursuant to the 1999 Settlement Agreement and Decision No. 62103. Pursuant to the 1999 Settlement Agreement, the Fixed CTC would terminate upon the collection of $450 million or December 31, 2008, whichever came first. TEP estimated that it would have collected $450 million from the Fixed CTC by May 2008. Pursuant to Decision No. 69568, the Commission allowed TEP to continue to collect the Fixed CTC Revenues after the collection of the $450 million, subject to true-up in the current proceeding.

[2] Specifically, Decision No. 69568 ordered as follows:

> IT IS THEREFORE ORDERED that Tucson Electric Power Company shall file the Rate Proposals initiating the Rate Proposal Docket on or before July 2, 2007.
>
> IT IS FURTHER ORDERED that the new Rate Proposal Docket shall be consolidated with the instant docket; all intervenors in this docket shall, unless they indicate otherwise, be deemed intervenors in the Rate Proposal Docket and do not need to seek separate intervention; and Tucson Electric Power Company shall serve copies of its filing in the Rate Proposal Docket on all parties of record in the instant docket.
>
> IT IS FURTHER ORDERED that Tucson Electric Company shall file a detailed DSM Portfolio based upon Tucson Electric Company's existing and proposed DSM programs and a Renewable Energy Action Plan with the Commission by July 2, 2007. The DSM Portfolio and REAP, together with information regarding cost recovery thereof, shall be filed in separate dockets.
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> IT IS FURTHER ORDERED that all existing rights and claims of Tucson Electric Power Company, Staff and the Intervenors arising out of the 1999 Settlement Agreement and Decision No. 62103 are fully preserved.
>
> IT IS FURTHER ORDERED that Tucson Electric Power Company's current Standard Offer rates for all retail customers shall remain at their current level, pending Commission determination of a refund or credit or other mechanism to protect customers, until the effective date of a final order in the Rate Proposal Docket.
>
> IT IS FURTHER ORDERED that in order to maintain Tucson Electric Power Company's Standard Offer rates at their current level, the Fixed CTC charge shall continue beyond the time it would otherwise termination (sic) under the 1999 Settlement Agreement until further Order of the Commission.
>
> IT IS FURTHER ORDERED that the incremental revenue collected as a result of retaining the Fixed CTC and maintaining Standard Offer rates at their current level shall be treated as "True Up Revenue" as discussed herein, and shall accrue interest and shall be subject to refund, credit or other mechanism to protect customers as determined

On July 2, 2007, TEP filed a rate application in Docket No. E-01933A-07-402 ("2007 Rate Application"); a DSM Portfolio in Docket No. E-01933A-07-0401; and a Renewable Energy Action Plan in Docket No. R-01933A-07-0400.

The 2007 Rate Application and the Motion to Amend (Docket No. E-01933A-05-0650) were consolidated. The Renewable Energy Action Plan was superseded by the TEP Renewable Energy Standard & Tariff ("REST") Implementation Plan, approved as modified by the Commission in Decision No. 70313 (April 28, 2008).

The 2007 Rate Application proposed three alternative rate methodologies: (i) the Market Methodology, (ii) the Cost-of-Service Methodology, and (iii) the Hybrid Methodology. TEP proposed a base rate increase of $267.57 million (a 21.9 percent increase) under the Market Methodology; an increase of $275.80 (23 percent) under the Cost-of-Service Methodology, comprised of a $158.20 million base rate increase and an additional $117.60 million for a "Transition Cost Regulatory Asset" surcharge ("TCRAC"); and a base rate increase of $212.54 million (14.9 percent) under the Hybrid Methodology. The dollar amounts of the proposed base rate increases excluded DSM charges and the Fixed CTC. The percentage increases are calculated based on TEP's 2006 test year revenue that included DSM and the Fixed CTC Revenue.

A number of parties intervened in the 2007 Rate Application, including Arizonans for Electric Choice and Competition and Phelps Dodge Mining Company (collectively "AECC"); U. S. Department of Defense and all other Federal Executive Agencies (collectively "DOD"); the Residential Utility Consumer Office ("RUCO"); Arizona Investment Council ("AIC"); International Brotherhood of Electric Workers Local 1116 ("IBEW"); Mesquite Power, LLC, Southwestern Power Group II, LLC Bowie Power Station, LLC, and Sempra Energy Solutions, LLC (collectively "Mesquite"); the Kroger Company ("Kroger"); Southwest Energy Efficiency Project ("SWEEP"); Western Resource Associates ("WRA"), Arizona Public Service ("APS"); the Arizona Competitive Power Alliance (the "Alliance"); Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC") and

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by the Commission in the forthcoming rate case docket.

the following individuals: Ms. Cynthia Zwick, a member of the Arizona Community Action Association ("ACAA"); and Mr. Billy Burtnett and Mr. John O'Hare, TEP residential customers.

On February 29, and March 14, 2008, Staff, RUCO, DOD, AECC, Kroger and Mesquite filed their direct testimony in the consolidated dockets. Staff, RUCO and AECC proposed utilizing a cost of service methodology and proposed new base rates for TEP. Staff proposed a base rate increase of $9.77 million over TEP's 2006 test year adjusted revenues, which excluded Fixed CTC and DSM revenues. Staff's base rate recommendation excluded the impact of the DSM, REST and PPFAC adjustors. AECC proposed a base rate increase not to exceed $91.62 million using the same baseline as Staff. RUCO proposed a base rate increase of $36.24 million.

TEP's average retail rate of approximately 8.4 cents/kWh during the 2006 test year includes revenue for the collection of the Fixed CTC. Staff's and RUCO's base rate recommendations as expressed in their direct testimony, would have resulted in decreases from the Company's 2006 average retail rate. Staff, RUCO and AECC opposed TEP's proposed TCRAC.

On April 1, 2008, TEP filed its Rebuttal Testimony.

On April 3, 2008, TEP filed a notice of settlement discussions, inviting all parties to attend settlement discussions. The parties to the proceeding held settlement discussions and subsequently, given those discussions, on April 18, 2008, Staff filed a motion to postpone the filing of Surrebuttal testimony. By Procedural Order dated April 21, 2008, Staff's request was granted and the further filing of testimony was suspended pending the outcome of settlement discussions.

On April 23, 2008, TEP filed a notice that it and Staff had reached an agreement in principal on the terms of a settlement. A Procedural Order dated May 1, 2008, set a Procedural Conference on May 8, 2008, to set a schedule and determine a process for considering the settlement. As of the May 8, 2008 Procedural Conference, the parties had not finalized the settlement and it was not clear which of the other parties besides TEP and Staff would join in the agreement.

By Procedural Order dated May 12, 2008, a schedule for filing the settlement agreement and testimony in support or opposition was established, and the hearing on the proposed settlement was set to commence on July 9, 2008. The May 12, 2008 Procedural Order directed all parties to the Settlement Agreement to file testimony in support of the agreement.

On May 12, 2008, (the date that had been noticed for the hearing on the 2007 Rate Application) the Commission convened for the purpose of taking public comment. Representatives of the City of Tucson and the Arizona Solar Alliance appeared to make public comment. In addition, the Commission received approximately 13 emails, calls, or written comments from consumers opposed to a rate increase. At the beginning of the July 9, 2008 hearing, representatives of the Pima County Community Action Agency and the City of Tucson appeared to make public comment. In addition, the Commission received an emailed comment specifically addressing the terms of the settlement.

On May 29, 2008, Staff filed a copy of a Settlement Agreement and Exhibits ("2008 Settlement Agreement") executed by TEP, Staff, AECC, ACAA, DOD, AIC, IBEW, Mesquite and Kroger (collectively "Signatories"). Testimony indicates that RUCO attended a number of the settlement discussions, but did not participate in discussions and did not sign the 2008 Settlement Agreement. SWEEP also did not execute the 2008 Settlement Agreement, but indicated that it does not oppose it.

On June 11, 2008, TEP, Staff, Mesquite, Kroger, DOD, AECC, Ms. Zwick and AIC filed direct testimony or comments in support of the proposed 2008 Settlement Agreement. IBEW obtained an extension, and filed its testimony in support of the 2008 Settlement Agreement on June 19, 2008.

On July 2, 2008, RUCO filed testimony in opposition to the 2008 Settlement Agreement. On the same date, SWEEP filed its testimony commenting on the settlement.

On July 7, 2009, TEP filed rebuttal testimony in support of the 2008 Settlement Agreement.

The hearing convened before a duly authorized Administrative Law Judge as scheduled on July 9, through July 16, 2008, at the Commission's office in Tucson, Arizona.

On August 29, 2008, TEP, Staff, RUCO, DOD, AECC, Mesquite, Kroger, SWEEP and AIC filed Closing Briefs.[3] The IBEW and Ms. Zwick did not file Closing Briefs.

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[3] On September 2, 2008, RUCO filed a Notice of Errata containing several revisions to its Brief.

II. The 2008 Settlement Agreement

A copy of the 2008 Settlement Agreement is attached hereto as Exhibit "A". Section I provides the background that led to the agreement. The 2008 Settlement Agreement provides that it is intended to settle all issues presented by Docket Nos. E-01933A-07-0402 and E-01933A-05-0650 in a manner that will promote the public interest.[4]

Section II addresses the amount of the rate increase. It provides that the fair value of TEP's rate base is $1,451,558,000, and that a reasonable fair value rate of return is 5.64 percent. The 2008 Settlement Agreement determines that TEP's generation rates will be determined using a Cost-of-Service methodology.[5] According to its terms, the 2008 Settlement Agreement provides for an increase in base rates of $47.1 million, or approximately 6 percent (from $781.1 million to $828.2 million), over the current rates, excluding the impact of the PPFAC, DSM Adjustor and the Renewable Energy Adjustor.[6] Under the terms of the 2008 Settlement Agreement the new average retail base rate will be 8.9 cents per kWh (as compared to the current average rate of 8.4 cents for kWh). In determining the effect of the rate increase, the 2008 Settlement Agreement includes the Fixed CTC in current rates.[7] The proposed rate increase under the 2008 Settlement Agreement is approximately $136.8 million over TEP's adjusted current base rates, not including the Fixed CTC.[8]

Section III addresses ratemaking treatment of generation assets and fuel costs. The Signatories agreed that for ratemaking purposes TEP's Springerville Unit 1 and the Luna Generating Station are included in TEP's rate base at their respective original costs.[9] They agree that new generation assets are to be included in TEP's rate base at their respective original costs, subject to subsequent ratemaking review. Further, they agree recovery of Springerville Unit 1 non-fuel costs should reflect a cost of $25.67 per kW per month.[10] The 2008 Settlement Agreement provides for an average base cost of fuel and purchased power reflected in base rates of $0.028896/kWh.[11]

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[4] 2008 Settlement Agreement ("SA") Section 1.14.
[5] SA Section 2.2.
[6] SA Section 2.3.
[7] Id.
[8] SA Section 2.4.
[9] SA Section 3.1.
[10] SA Section 3.2.
[11] SA Section 3.4.

Section IV of the 2008 Settlement Agreement addresses the Cost of Capital. The Signatories agree to adopt a capital structure comprised of 57.5 percent debt and 42.5 percent common equity.[12] They agree on a return on common equity of 10.25 percent and embedded cost of debt of 6.38 percent, with a fair value rate of return of 5.64 percent.[13]

Section V addresses depreciation and cost of removal. The 2008 Settlement Agreement adopts depreciation rates for distribution and general plant on a going-forward basis. The agreed-upon depreciation rates include an annual accrual of $21,626,296 for costs of removal for "generation" excluding the Luna Generating Station, which has separately identified depreciation rates as part of the agreement.

Section VI established an Implementation Cost Recovery Asset ("ICRA"). The 2008 Settlement Agreement includes an ICRA of $14,212,843, which reflects costs TEP incurred in the transition to retail electric competition as follows:

Deferred Direct Access Costs	$11,153,016
Deferred Divestiture Costs	1,193,003
Deferred GenCo Separation Costs	164,026
Deferred Desert Star and West Connect Funding	1,702,798
Total	14,212,843

For ratemaking purposes, the 2008 Settlement Agreement provides that the ICRA is to be amortized over a four-year period, and that it will not be included in rate base or as an amortization expense in TEP's next rate case.[14]

Section VII addresses the Purchased Power and Fuel Adjustment Clause ("PPFAC"). TEP currently does not have a PPFAC. The 2008 Settlement Agreement's PPFAC allows fuel and purchased power costs incurred to serve retail customers, and includes the "prudent direct costs of

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[12] SA Section 4.1. By way of comparison, in pre-settlement testimony, Staff recommended a return on equity of 10.25 percent with a capital structure comprised of 39.9 percent equity and 60.1 percent debt (Ex S-1 Parcell Direct at 2). Staff's recommendation was based on TEP's actual capital structure. TEP proposed a hypothetical capital structure comprised of 55 percent debt and 45 percent equity, with a return on equity of 10.75 percent. If TEP's actual capital structure were used, TEP proposed a cost of equity of 11.75 percent. (Ex TEP-1 Hadaway Direct at 2). RUCO proposed a cost of equity of 9.44 percent and a pro forma capital structure comprised of 55 percent debt and 45 percent equity (Ex RUCO-1, Rigby Direct at 47-50).

[13] SA Sections 4.2 and 4.3.

[14] SA Section 6.2.

contracts used for hedging system fuel and purchased power."[15] The PPFAC is described in greater detail in the Plan of Administration ("POA") which is attached to the 2008 Settlement Agreement as Exhibit 6. The proposed PPFAC consists of a Forward Component and a True-up Component.[16] It is proposed that the PPFAC mechanism will be effective starting January 1, 2009, and will be initially set at zero. The first PPFAC Year would run from April 1, 2009, through March 31, 2010, and the first True-up Component would encompass the period from January 1, 2009, through March 31, 2009. The Forward Component is proposed to be updated on April 1 of each year beginning April 1, 2009, and consists of the forecasted fuel and purchased power costs for the year commencing April 1st and ending March 31st of the ensuing year, less the average Base Cost of Fuel and Purchased Power reflected in base rates (i.e. $0.028896 per kWh).[17] The True-up Component will reconcile any over-recovered or under-recovered amounts from the preceding PPFAC Year which will be credited to, or recovered from, customers in the next PPFAC Year.[18]

According to the 2008 Settlement Agreement and POA, TEP will file the PPFAC Rate with all component calculations for the upcoming PPFAC Year, including all supporting data, with the Commission on or before October 31st of each year, and will update the October 31st filing by February 1st of the next year.[19] Interested parties could make objections to the October 31st filing within 45 days of the filing[20] and any objections to the February update filing within 15 days.[21] The 2008 Settlement Agreement provides that TEP can request an adjustment to the Forward Component at any time during a PPFAC Year "should an extraordinary event occur that causes a drastic change in forecasted fuel and purchased power prices."[22]

In addition, all short-term Wholesale Sales Revenue,[23] ten percent of annual positive wholesale trading profits,[24] and 50 percent of the revenues from sales of sulfur dioxide (SO2)

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[15] SA Section 7.2(a).
[16] SA Section 7.29(d) & POA Sections 2 & 3.
[17] SA Section 7.2(f).
[18] SA Section 7.2(g).
[19] SA Section 7.2 (h) & POA Section 5.
[20] POA Section 5.D.
[21] Id.
[22] SA Section 7.2(i).
[23] SA Section 7.2(j).
[24] SA Section 7.2(k).

emission allowances will be credited to fuel and purchased power costs.[25] The 2008 Settlement Agreement provides that under no circumstances will any annual net loss on wholesale trading incurred by TEP be shared with, or borne by, ratepayers.[26] Further, the Commission or Staff may review the prudence of fuel and power purchases at any time and no change to the PPFAC rate will become effective without Commission approval.[27]

Section VIII of the 2008 Settlement Agreement addresses the Renewable Energy Adjustor. The Signatories adopt the REST Adjustor Mechanism as recommended in Staff's Direct Rate Design Testimony.[28] The initial rates for the REST Adjustor Mechanism will be the same as approved in Decision No. 70314, and subsequent changes will be set in connection with the annual Renewable Energy Implementation Plan submitted by TEP and approved by the Commission pursuant to the REST rules.[29]

Section IX of the 2008 Settlement Agreement addresses DSM Programs and Adjustor. The Signatories state that they support the implementation of an appropriate DSM Portfolio and related Adjustor, and would use their best efforts to implement such DSM Portfolio and Adjustor as soon as possible.[30] The 2008 Settlement Agreement provides for an initial funding level of $6,384,625 for the prudent costs of Commission-approved DSM programs.[31] To achieve the initial funding level, the Signatories agreed upon an initial adjustor rate of $0.000639/kWh applied to all kWh sales.[32] The Signatories adopt the performance incentive for the DSM adjustor mechanism as recommended by Staff in its Direct Rate Design Testimony.[33] Pursuant to the agreement, TEP will file an application by April 1st of each year for Commission approval to reset the DSM Adjustor rates, and rates would be reset on June 1st of each year.[34] TEP may continue to propose new DSM programs for Commission review and approval.

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25 SA Section 7.2(l).
26 SA Section 7.2(k).
27 SA Section 7.2(n) & (p); POA Section 5.B.
28 SA Section 8.1; Ex S-1 Parcell Direct at 2.
29 SA Sections 8.2 and 8.3.
30 SA Section 9.1.
31 SA Section 9.2.
32 Id..
33 SA Section 9.3; Ex S-1 Keene Direct at4-6.
34 SA Section 9.5.

Section X of the 2008 Settlement Agreement provides for a Rate Case Moratorium. The Settlement Agreement provides that TEP's base rates would remain frozen through December 31, 2012, and no Signatory would seek any change to TEP's base rates that would take effect before January 1, 2013.[35] The Agreement provides that TEP would not submit a rate application sooner than June 30, 2012, and that TEP may not use a test year earlier than December 31, 2011.

Section XI provides for an Emergency Clause, under which TEP could request a change in its base rates, or PPFAC mechanism, DSM adjustor mechanism or the REST adjustor mechanism prior to January 1, 2013, in the event of an "emergency."[36] For purposes of the 2008 Settlement Agreement, "emergency" is "limited to an extraordinary event that is beyond TEP's control and that, in the Commission's judgment, requires rate relief in order to protect the public interest."[37] This section provides further that it "is not intended to preclude TEP from seeking rate relief pursuant to this paragraph in the event of the imposition of a federal carbon tax or related federal 'cap and trade' system." The Signatories state further that this section is not intended to preclude any party from opposing a TEP application for rate relief.

Section XII addresses TEP's Certificate of Convenience and Necessity ("CC&N"). The 2008 Settlement Agreement provides that it is not intended "to create, confirm, diminish, or expand" the exclusivity of TEP's service territory or its obligation to serve within its service territory. The Signatories agree that a generic docket is an appropriate means for the Commission to address the issue of the exclusivity of the service territories of "Affected Utilities" as defined in A.A.C. R14-2-1601.1.[38] They acknowledge that TEP has the obligation to plan for and serve all customers in its certificated service area.[39] The 2008 Settlement Agreement does not bar any party from seeking to amend TEP's obligation to serve or the Commission's prospective ratemaking treatment of TEP.[40]

Section XIII provides for a Returning Customer Direct Access Charge ("RCDAC"). The 2008 Settlement Agreement states that TEP will file a RCDAC tariff, as a compliance item, within 90

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[35] SA Section 10.1.
[36] SA Section 11.1.
[37] Id.
[38] SA Section 12.1.
[39] SA Section 12.2.
[40] Id.

days of the effective date of the Commission Order approving the Agreement.[41] Pursuant to the 2008 Settlement Agreement, the RCDAC would apply only to individual customers or aggregated groups of customers with demand load of 3 MWs or greater and would not apply to customers who provide at least one year's advance written notice of intent to return to TEP generation service and to take TEP Standard Offer service. The RCDAC will be designed to recover from Direct Access customers the additional costs, both one-time and recurring, that these customers would otherwise impose on other Standard Offer customers if and when the former return to Standard Offer service, and shall be designed so that the RCDAC is paid in full within one year.[42]

Section XIV of the 2008 Settlement Agreement provides that because the transition to retail electric competition at the time of the 1999 Settlement Agreement was entered into and approved did not occur in the timeframes contemplated at the time, it is necessary to address the prospective regulatory treatment that is appropriate for TEP. Thus, the Signatories request that to the extent any party to the 1999 Settlement Agreement contends the 2008 Settlement Agreement is inconsistent with the 1999 Settlement Agreement, that Decision No. 62103 be amended to be consistent with the 2008 Settlement Agreement.[43] In this section, TEP agrees to forego all claims relating in any way to the 1999 Settlement Agreement or Decision No. 62103, including any damages related to its alleged breach of contract claim, to setting its rates under cost-of-service ratemaking principles, or to the rate freeze adopted in Decision No. 62103.[44] In addition, the 2008 Settlement Agreement notes that the 1999 Settlement Agreement contained certain waivers that may not continue to be in the public interest. In the 2008 Settlement Agreement, the Signatories agree that TEP will file an application with the Commission addressing all of the waivers within 90 days of the issuance of a Commission Order approving the Agreement.

Section XV of the 2008 Settlement Agreement addresses the handling of the True-up of the Fixed CTC Revenues. The parties to the 2008 Settlement Agreement were unable to resolve the issue of when rates under the 2008 Settlement Agreement would go into effect and how to treat the Fixed

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[41] SA Section 13.1.
[42] SA Section 13.1(d).
[43] SA Section 14.2.
[44] SA Sections 14.2 through 14.8.

CTC True-up Revenues as defined in Decision No. 69568.[45] TEP agrees that to the extent the Commission determines that Fixed CTC True-up Revenues should be credited to customers, an amount up to $32.5 million shall be credited to customers in the PPFAC balancing account.[46] The 2008 Settlement Agreement provides that the Commission shall determine the disposition of additional Fixed CTC True-up Revenues, if any, to be credited to customers.[47]

Section XVI addresses Rate Design issues. The settlement provides that the base revenue increase is to be spread equally across all customers. Because low income customers will be held harmless from any increase in base rates, other customers will experience an approximate 6.1 percent increase in base rates over current base rates including the Fixed CTC.[48] The 2008 Settlement Agreement also provides for inclining block rate structures in order to encourage energy conservation.[49] In addition, the 2008 Settlement Agreement acknowledges that expanding TOU rates is in the public interest. The agreement provides that all TOU rate schedules will be made available on an optional basis. Under the 2008 Settlement Agreement, TEP will offer three new optional residential TOU schedules that will replace the current (to-be-frozen) Rate 70.[50] The current residential TOU rate schedules will remain available to existing customers but will not be available to new customers. In addition, the parties agreed that the customer charge for the Residential Rate 01 shall be $7.00 per month; that TOU Large General Service Rate 85N and Large Light and Power Rate 90N shall be seasonally differentiated and have substantial non-fuel cost recovery through demand charges; that unbundled rates shall be designed such that the generation component is near

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[45] SA Section 15.1.
[46] SA Section 15.2.
[47] SA Section 15.3.
[48] SA Section 16.1. Testimony indicates that because of the inclining block rate structure, the average residential customer, with usage of 900 KWhs/month will see a 3.2 percent base rate increase, from $84.55 to $87.25, plus an estimated additional 4.9 percent increase attributable to the PPFAC and the DSM Adjustor.
[49] SA Sections 16.3 through 16.6. TEP's witnesses testified that residential customers, with average use of 900 kWhs/month would see an increase from $84.55 to $86.23, or 3.2 percent due to the proposed base rate increase, and that the increase is lower than the 6 percent due to the impact of the proposed inclining block rate structure. ExTEP-2, Pignatelli Settlement Direct at 14. See also Ex TEP-6, Dukes Settlement Direct at 3. Mr. Duke testified that using TEP's hypothetical PPFAC charge and proposed DSM charge, the median and average residential customer would see a bill increase of 4.9 percent attributed to those charges.
[50] SA Sections 16.7 through 16.18.

cost and the transmission component is tied to the FERC Open Access Transmission Tariff ("OATT").[51]

The 2008 Settlement Agreement provides that the increase in base revenue will not apply to the existing low-income programs, which will have the effect of holding low-income customers harmless from the rate increase.[52] In addition, low income customers taking service under the low income tariffs will not be subject to the PPFAC.[53] The incremental fuel and purchased power costs that these low-income customers would have otherwise paid under the PPFAC will be recovered from all remaining customers subject to the PPFAC.[54]

Section XVII addresses Rules and Regulations. TEP was to file any proposed changes to its Rules and Regulations by June 11, 2008, and the Signatories agreed to raise any issues regarding those Rules and Regulations at the hearing on the 2008 Settlement Agreement.[55] Among the significant changes to its rules is the elimination of free footage from TEP's line extension tariffs.[56]

Section XVIII of the 2008 Settlement Agreement provides for additional Tariff filings. Pursuant to the agreement, TEP will file within 90 days of the effective date of a Commission Order approving the agreement the following tariffs: new Partial Requirements Tariff; an Interruptible Tariff; a Demand Response Program Tariff; and a Bill Estimation Tariff.

Section XIX provides that TEP agrees to implement the fuel audit recommendations set forth by Staff in its Direct Testimony, except that the fuel audit recommendations need not be completed prior to the implementation of the PPFAC. TEP agrees to file an implementation plan within 90 days of a Commission Order approving the 2008 Settlement Agreement.

Finally, Section XX contains Miscellaneous Provisions. In this section, the Signatories reserve their pre-settlement positions in the event the Commission does not approve the 2008 Settlement Agreement and provide that if the Commission does not issue a final Order before December 31, 2008, any Signatory may withdraw from the agreement.

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[51] SA Sections 16.24 through 16.26.
[52] SA Section 16.28.
[53] SA Section 16.31.
[54] *Id.*
[55] SA Sections 17.1 and 17.2. TEP made the requisite filing.
[56] SA Section 17.3.

III. Arguments

A. The Signatories' Positions

At the hearing on the 2008 Settlement Agreement and in the Closing Briefs, the Signatories offered evidence and argued that the 2008 Settlement Agreement is innovative, fair and balanced, and in the public interest. In general, the Signatories testified that this was a complex case, the resolution of which was the product of an open, fair and transparent process that brought together parties with far-ranging interests and positions. They assert that the record shows the 2008 Settlement Agreement provides benefits to TEP customers, employees and shareholders.[57] According to AIC, not only does the 2008 Settlement Agreement resolve a number of issues in a positive and productive way, it stands in remarkable and positive contrast to the experience of many other states which have exited from retail electric competition experiences.[58]

TEP criticizes RUCO's opposition, claiming RUCO appears to want TEP to accept the obligations of the 2008 Settlement Agreement without sufficient funds to do so, which TEP argues is not in the public interest.[59]

1. The Settlement Negotiation Process

Mr. Johnson, on behalf of Staff, described an unprecedentedly open, fair and transparent negotiation process.[60] Mr. Smith, a consultant for Staff also testified that it was probably the most open settlement discussion in which he has ever been involved in his 28 years of regulatory consulting.[61] TEP, AIC, DOD, and AECC expressed similar opinions.[62] TEP notes that even RUCO acknowledged that it was an open process.[63]

2. Resolution of Claims under 1999 Settlement Agreement

The Signatories assert that the 2008 Settlement Agreement is in the public interest because it resolves complex and potentially disruptive claims arising from the 1999 Settlement Agreement. TEP has argued for some time that pursuant to the terms of the 1999 Settlement Agreement and

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[57] TEP Brief at 4; Staff Brief at 5, DOD Brief at 2, AECC Brief at 3.
[58] AIC Brief at 8.
[59] TEP Brief at 32.
[60] Transcript of July 9, 2008 hearing "Tr" at 360.
[61] Tr at 694.
[62] TEP Brief at 3, AECC Brief at 3, AIC Brief at 2, Tr at 419.
[63] Tr at 977.

Decision No. 62103, commencing on January 1, 2009, its generation rates would be set by the market according to the formula established in the 1999 Settlement Agreement. Other parties to the 1999 Settlement Agreement disagreed with TEP, and argued that at the end of the rate moratorium established in the 1999 Settlement Agreement, the Commission could set rates based on Cost-of-Service or other reasonable methodology. The Signatories argue that by resolving the question that TEP's generation assets would return to Cost-of-Service regulation and that TEP would release its claims for damages under a return to Cost-of-Service regulation, the 2008 Settlement Agreement avoids time-consuming and costly litigation and the risk that the Commission could lose regulatory control over these assets.[64]

Staff has stated that TEP's acceptance of the Cost-of-Service methodology was crucial to reaching a settlement.[65] AECC believes the resolution of the Cost-of-Service issues in conjunction with the 6 percent base rate increase is the strongest part of the Agreement as it protects ratepayers from the effects of market risks.[66] TEP asserts that resolving these issues aids investor confidence and provides for regulatory certainty.[67]

3. Base Rate Increase

TEP argues that the evidence in the record established that TEP must make substantial investments, estimated at $1.2 billion, in its system over the next five years and argues that the rates approved in this proceeding must be sufficient to allow TEP to attract capital.[68] TEP expressed concern over the effects of inflation on pension costs, healthcare costs and operation and maintenance costs, and argues the rate increase in the 2008 Settlement Agreement is the minimum needed to maintain TEP's quality of service.[69]

The Signatories argue the rate increase under the 2008 Settlement Agreement is modest under the circumstances. TEP notes that when it submitted its rate case filing, it provided three different alternatives for determining rates, the market approach, Cost-of-Service and hybrid methodology,

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[64] TEP Brief at 5; Staff Brief at 8; AECC Brief at 5; AIC Brief at 3.
[65] Staff Brief at 8.
[66] AECC Brief at 5; Tr at 630.
[67] Tr at 111.
[68] Tr at 111, TEP Brief at 6.
[69] TEP Brief at 6.

with expected rate increases ranging from 15 to 23 percent.[70] Mr. Pignatelli testified that if TEP were to charge market-based rates, the increase could be 53 percent.[71] The Signatories note that the 6 percent increase in base rates is substantially less than the $180.7 million TEP sought under its proposed Cost-of-Service methodology.[72] They believe it is important to put the current increase in context, as the 6 percent base rate increase comes after 14 years of stable/declining rates, and that the projected average residential user impact is actually only slightly more than 3 percent due to the inclining block rate structure.[73] They note further that ratepayers are able to mitigate some of the impact of the increase because of the proposed inclining block rate structure and the new TOU rates.[74] TEP states that the average residential customer uses 900 kWh per month.[75] TEP asserts the inverted block rates, without the DSM surcharge, would increase the average residential bill by only 3.2 percent, from $84.55 to $87.25, and with the DSM surcharge, would increase the monthly bill to $87.81.[76]

TEP argues that the base rate increase must be viewed in connection with the base rate moratorium, which TEP had not included in its original request and the adoption of a PPFAC that was designed by Staff and substantially different from the PPFAC originally proposed by TEP.[77] Furthermore, the Signatories note that the 2008 Settlement Agreement protects TEP's low income customers from the base rate increase and from the potential additional costs of the PPFAC.

TEP argues that RUCO's opposition to the base rate increase is without foundation or analysis and that RUCO could not provide an estimate of what would be an appropriate increase.[78] Furthermore, TEP argues that RUCO did not respond in any meaningful way to any of the problems with RUCO's revenue requirement that TEP had addressed in its rebuttal testimony, instead clinging to its litigation position.[79]

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[70] TEP Brief at 7.
[71] Tr at 268.
[72] TEP Brief at 7; AECC Brief at 8.
[73] AIC Brief at 2.
[74] AIC Brief at 2; TEP Brief at 8; Staff Brief at 14.
[75] Ex TEP-6, Dukes Settlement Direct at 5-6.
[76] TEP Brief at 9.
[77] TEP Brief at 7.
[78] TEP Brief at 8.
[79] TEP Brief at 33.

4. **Generation Assets**

TEP argues the 2008 Settlement Agreement is in the public interest because it provides clarity and certainty regarding the rate base treatment for the Luna Generating Station.[80] TEP testified that it acquired the Luna Generation Station in 2004 for approximately $250/kw, and did not use ratepayer funds.[81] TEP had wanted to keep the Luna Generating Station out of rate base or to include it at its current market value, which is approximately $1,000/kw.[82] Under the proposed settlement, TEP agrees to include the Luna Generating Station at its book value as of December 31, 2006, and argues such treatment of the Luna Generating Plant is a tremendous benefit to rate payers.[83]

In addition, the 2008 Settlement Agreement provides for Springerville Unit 1 to be placed into rate base at cost and provides that the non-fuel costs for Springerville Unit 1 are $25.67 per kW per month. The parties had disputed the Springerville Unit 1 non-fuel costs in their pre-settlement testimonies. TEP argues the resolution of this dispute in a just and reasonable way is a benefit of the 2008 Settlement Agreement.[84] TEP asserts that although RUCO has opposed the $25.67 per kW per month estimate of the cost, RUCO did not provide a credible analysis of the amount.

5. **Cost of Capital**

TEP argues that the 2008 Settlement Agreement is in the public interest because it resolves the dispute regarding TEP's cost of capital in a reasonable manner. In the underlying rate case, TEP sought a capital structure of 55 percent debt and 45 percent equity, a cost of equity of 10.75 percent, an embedded cost of debt of 6.39 percent and a weighted average cost of capital of 8.35 percent.[85] The 2008 Settlement Agreement provides a capital structure of 57.5 percent debt, 42.50 percent equity and that return on equity of 10.25 percent, embedded cost of debt of 6.38 percent and a weighted cost of capital of 8.03 percent. TEP notes that it has agreed to a cost of equity 50 basis points lower than its request and lower than the rate recently approved for APS.[86]

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[80] TEP Brief at 9.
[81] Tr at 107.
[82] Tr at 107; Tr at 812.
[83] Tr at 107; TEP Brief at 10.
[84] TEP Brief at 10.
[85] Ex TEP-7 Larson Direct at 3.
[86] TEP Brief at 11.

6. **Depreciation and Cost of Removal**

The issue surrounding depreciation involves TEP's determination that its generation had been deregulated after the Commission issued Decision No. 62103, and its implementation of Financial Accounting Standards ("FAS") No. 143, entitled "Accounting for Asset Retirement Obligations." TEP's adoption of FAS No. 143 reduced Accumulated Depreciation by $112.8 million to remove previously recorded Accumulated Depreciation that it had collected for estimated future costs of removal through the end of 2002.[87] TEP also reduced subsequent accruals of Depreciation Expense because TEP removed the cost of removal component from its depreciation rates for generation.[88] Staff explains that rather than make an adjustment to test year rate base, the 2008 Settlement Agreement addresses this concern by providing for a rate case moratorium and for depreciation rates for TEP's generating plant that include $21.6 million per year for cost removal.[89] TEP expressed concerns that if the Commission had disallowed TEP's accounting interpretation of FAS 143, TEP would be forced to write-off certain assets.

Staff and TEP argue the 2008 Settlement Agreement resolved the issue of ratemaking treatment for depreciation and cost of removal in a positive and reasonable manner.[90] The 2008 Settlement Agreement, in addition to setting depreciation rates going forward, provides for an annual accrual for the cost of removal for TEP's generation assets.[91] Staff asserts that during the rate moratorium period, this provision will provide future ratepayer benefit by building up the balance of Accumulated Depreciation related to the cost of removal in a manner that may not have been achievable without the Agreement.[92] Staff acknowledges that write-offs might negatively affect TEP's financial viability.[93]

TEP argues that although RUCO took issue with this resolution, it could not claim the settlement position is unreasonable.[94]

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[87] TEP Brief at 9.
[88] Ex S-4 at 8; TR 735-736.
[89] Staff Brief at 9.
[90] TEP Brief at 12; Staff Brief at 9.
[91] TEP Brief at 12.
[92] Staff Brief at 9.
[93] Tr at 671.
[94] TEP Brief at 12.

7. Implementation Cost Recovery Asset ("ICRA")

The 2008 Settlement Agreement includes an ICRA of $14,212,843 that reflects the costs that TEP incurred in its transition to retail electric competition under the 1999 Settlement Agreement. TEP asserts that while it originally argued it incurred significantly higher costs under the transition, TEP agreed to accept the lower amount as part of the integrated 2008 Settlement Agreement. TEP argues the reduction from TEP's original position is a clearly defined benefit to TEP's customers.[95] TEP notes that RUCO does not oppose this provision.[96]

8. PPFAC

The Signatories argue that the adoption of the PPFAC in the 2008 Settlement Agreement is in the public interest as it allows TEP to recover the costs of its fuel and purchased power in a timely manner.[97] TEP does not currently have a PPFAC, and yet, TEP states, the Company increasingly relies on significant quantities of natural gas and purchased power, the costs of which have steadily risen since 2006.[98] TEP asserts that without a PPFAC, TEP could not agree to only a 6 percent base rate increase, but would have negotiated a much higher increase.[99] In addition, TEP asserts, without the PPFAC, TEP would be required to file more frequent base rate cases, and would constantly be trying to "play catch up" because of the time necessary to process a rate case.[100]

TEP asserts that RUCO did not present any evidence at the settlement hearing that suggested it had evaluated the proposed PPFAC, but merely adhered to its original position that a different type of fuel clause should be adopted.[101] TEP argues the PPFAC in the 2008 Settlement Agreement benefits customers by protecting them from price spikes.[102] TEP notes that the Adjustor amount would be set for the year, with the effect that a spike in prices in any given month would be absorbed until the new PPFAC rate is set. Thus, according to TEP, the effect of a price spike is dampened and smoothed out over the year. TEP states that any over- or under-collection is returned or charged to

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[95] TEP Brief at 13.
[96] Tr at 1071.
[97] TEP Brief at 13, Staff Brief at 9; AIC Brief at 3; Mesquite Brief at 3; AECC Brief at 6.
[98] Tr at 124, 220-21, 258.
[99] TEP Brief at 13.
[100] TEP Brief at 14.
[101] Id.
[102] Id.

customers over the subsequent 12-month period.[103] TEP argues the proposed PPFAC provides customers with proper price signals about the real costs of energy consumption and assists them to adjust their energy usage based on the cost of their consumption.[104] TEP asserts the offsets and credits provided for in the proposed PPFAC also benefit consumers; and give consumers the benefit of credits that they otherwise would not see as there is no nexus between these credits and ratepayers.[105]

TEP argues further, that the PPFAC benefits ratepayers by lowering TEP's cost of capital.[106] TEP states that it agreed to a lower return on equity and a capital structure with less equity than it proposed because of the reduced risk it would face as a result of the PPFAC.[107]

TEP argues the 2008 Settlement Agreement provides the significant safeguard that any adjustment of the PPFAC rate will be subject to scrutiny by Staff and interested parties, and no change would be made without a Commission order.[108] Mr. Hutchens for TEP testified that that the Company is amenable to working with any reasonable process that the Commission or Staff establishes.[109]

AIC believes that from the shareholder point of view, the implementation of the PPFAC is a critical factor capital markets use to evaluate the risks of investing in or lending money to TEP. AIC asserts the 6 percent base rate increase in this case, to be followed by another rate moratorium, stands in sharp contrast to the experiences in other states coming out of rate freezes which are seeing increases ranging from 12 to 70 percent.[110] AIC believes this is remarkable given the cost of providing service has risen dramatically over the period. In addition, AIC argues that in opposing the settlement, RUCO concentrated only on those issues that favored TEP and ignored areas that the Company conceded. AIC criticized RUCO for offering no affirmative solutions.[111]

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[103] TEP Brief at 15.
[104] Id..
[105] Id.
[106] TEP Brief at 16.
[107] Id.
[108] Id.
[109] Tr at 863.
[110] AIC Brief at 4, citing the presentation of Ken Rose, senior fellow at Michigan State's Institute of Public Utilities, at an Open Meeting in October 2007.
[111] AIC Brief at 5.

Mesquite believes a well–conceived and designed PPFAC is important for TEP to maintain its creditworthiness. Mesquite, comprising wholesale power suppliers, argues that it is important for TEP to be afforded the opportunity to receive revenues sufficient to remain a creditworthy purchaser in the competitive wholesale electrical market in Arizona. Mesquite believes this is especially important given TEP's increasing need to look to the wholesale market to supply its power requirements.[112] Mr. Huchens testified for TEP that in 2007, TEP's fuel mix was 22 percent gas and 78 percent coal.[113] He testified further that every year, TEP expects the percentage of gas in its fuel mix increase to increase 3 percent. Mesquite notes that by 2015, TEP expects 30 to 40 percent of its demand will be satisfied through purchased power arrangements and natural gas purchases.[114] Mesquite cited Mr. Pignatelli's testimony that a PPFAC is needed to maintain its creditworthiness. According to Mesquite, under-collection of fuel costs can result in two types of problems that could adversely affect ratepayers: 1) the utility's providers of purchased power and fuel may require letters of credit or performance bonds which would increase the cost of the transaction; or 2) to the extent there is a significant time lag between incurring the purchased power expense and recovery from ratepayers, some ratepayers may pay a higher unit cost for demand caused by customers who have since left the utility's system.[115]

Mesquite's support for the PPFAC in the 2008 Settlement Agreement is expressly conditioned upon TEP's ongoing compliance with the Recommended Best Practices for Procurement which was adopted by the Commission in Decision No. 70032 (December 4, 2008). Mesquite agrees with, and supports, the recommendations of Staff concerning how the PPFAC and Plan of Administration will be implemented and administered.[116]

During the hearing, the question arose whether the proposed PPFAC should have a cap to mitigate the impact on ratepayers resulting from a spike in the cost of fuel. The proposed PPFAC was compared to the fuel adjustor the Commission approved for APS. Staff states that it did not propose a cap for the PPFAC in this matter or in the APS proceeding. Staff believes that while a cap

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[112] Tr at 125.
[113] Tr at 815.
[114] Tr at 162-164.
[115] Tr at 131-134
[116] Tr at 364-372; Tr at 909– 911; Tr 912–Tr 914.

may protect ratepayers from spikes in power supply costs, it can also cause the utility to carry large deferral balances.[117] Staff and TEP argue that the 2008 Settlement Agreement gives ratepayers more protection than is afforded under the APS adjustor because it can only be reset after Commission approval.[118]

TEP does not support a cap on PPFAC cost recovery in this case.[119] TEP asserts that it cannot afford to have its ability to recover the fuel and purchased power costs capped if the base cost of the fuel and purchased power is set at 2006 levels.[120] Further, TEP asserts that it cannot afford to lose recovery of cost increases for each year from 2009 through 2013.[121] TEP states the PPFAC structure is directly tied to the rate moratorium and argues that modifying the PPFAC would leave TEP exposed for costs that "could imperil TEP's finances."[122] In addition to sending inappropriate price signals to customers, TEP argues a cap on the PPFAC could create intergenerational imbalances as costs incurred by one set of ratepayers are borne by another set. TEP also asserts that any interest owed due to balances created by a cap would increase the cost to ratepayers, and the account balances and financial costs would affect TEP's credit and affect its ability to purchase fuel and purchased power at more favorable prices.[123]

AECC's witness, Mr. Higgins, testified that in evaluating the benefit of placing a cap on the PPFAC, the Commission should weigh the short-term benefit of the cap with the potential that under-collected amounts would have to be repaid with interest.[124] AECC notes too that the PPFAC includes a credit for 50 percent of the revenue from SO2 emission sales that is not in the APS PPFAC. AECC argues the 2008 Settlement Agreement needs to be viewed as a package, and that includes the PPFAC as currently proposed.[125]

In addition, unlike the APS fuel adjustor, the PPFAC proposed for TEP does not contain a 90/10 sharing arrangement. Staff believes that the proposed PPFAC contains provisions, such as the

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[117] Tr at 709.
[118] Staff Brief at 11; TEP Brief at 18.
[119] Tr at 210 & 217.
[120] TEP Brief at 17.
[121] Id.
[122] Id.
[123] TEP Brief at 18.
[124] AECC Brief at 6; Tr at 615.
[125] AECC Brief at 6.

emission credits and the 90/10 sharing on wholesale trading, to provide TEP with incentives to secure its fuel needs more competitively.[126] Staff notes the downside of a sharing arrangement, is that if costs decrease, customers have the potential to pay more than TEP's actual costs.[127]

9 **Rate Base Moratorium**

The 2008 Settlement Agreement provides that TEP will not submit a rate application sooner than June 30, 2012, and will not use a test year ending earlier than December 21, 2011. TEP argues this provision is in the public interest as it promotes rate stability for at least four more years and conserves the resources of both Staff and the Company in litigating a rate case.[128] AECC and Staff shared this belief.[129]

10. **Rate Design**

The Signatories assert that the 2008 Settlement Agreement provides an improved rate design that is just and reasonable and promotes energy conservation and protects low income customers.[130]

Staff believes that successful rate designs not only achieve the utility's goal of recovering its revenue requirement, but must consider other goals such as stability, fair apportionment of costs among customer classes, social equity, promoting cost-effective load management and energy conservation, investment in energy efficiency, simplicity for customers and ease of implementation for utilities.[131] Staff asserts the 2008 Settlement Agreement proposes an overall rate design with key features that address each of these goals.[132] Staff asserts that the proposed revenue allocation combined with inclining block rate structure, provide for fair apportionment of costs across all customer rate schedules. In addition to the new rate schedules for low income residential customers, the first block of the tiered rates provides for a lower base rate for consumption up to 500 kWh per month. Thus, small users, who are less likely to be able to take additional conservation measures, may see a rate decrease. Further, Staff asserts the TOU options and inclining block rate structure reflect a fair apportionment of costs, whereby customers are charged more during peak hours when

[126] Tr at 789.
[127] Tr 842-843.
[128] TEP Brief at 21.
[129] AECC Brief at 6; Tr at 336 and 350.
[130] TEP Brief at 22-23; Staff Brief at 11; DOD Brief at 3; AECC Brief at 7.
[131] Staff Brief at 11.
[132] Tr at 108-109; Tr 336-337.

the cost of providing electricity is greater, and thus, reflect an accurate price signal. Both the inverted rates and TOU rates are seasonally differentiated so that charges during the summer reflect the higher costs of power. According to Staff, the proposed rate structure gives customers the ability to reduce the impact of the increase by changing a few habits and conserving electricity. Staff believes the proposed rates will help reduce peak loads, increase supply security and encourage investment in energy efficiency and renewable resources.

One of the most innovative aspects of the 2008 Settlement Agreement is holding the low income customers harmless from the base rate and potential PPFAC increase. Ms. Zwick, whose interest is in protecting low income ratepayers, testified that this provision is unprecedented.[133]

Rate design issues were of particular importance to DOD, AECC and Kroger. DOD states that its primary purpose in intervening in this matter was to address cost of service and rate design issues, including large-customer DSM and the redesign of TEP's partial requirements service ("PRS") tariffs.[134] DOD did not take a specific position on revenue requirement or PPFAC issues. Although the DOD believes that the 6.1 percent across-the-board increase in rates under the 2008 Settlement Agreement is not consistent with the results of the class cost of service analysis, DOD believes that the other provisions of the agreement outweigh this factor. Specifically, DOD notes that the agreement provides for a significant improvement for the rate design applicable to large customers (i.e. demands exceeding 3,000 KW). DOD states that the rate designs in TEP's filing were not cost-based and would have penalized customers with high load factors, but the rates proposed in the 2008 Settlement Agreement represent a dramatic improvement.[135] DOD believes that by increasing the demand charges, and reducing the kWh charges, customers are encouraged to increase load factors and become more efficient in their use of power. DOD also believes the new optional TOU rate for large customers provides a strong incentive to reduce power costs by reducing or shifting peak demands. DOD asserts that the improved rate design was an important factor in its decision to sign the 2008 Settlement Agreement. In addition, DOD believes that TEP's current PRS

[133] Tr at 454.

[134] DOD Brief at 2. TEP provides electric service to two major DOD installations: Davis-Monthan Air Force Base ("DM") in Tucson and Fort Huachuca ("Fort") in Sierra Vista, which have a combined annual consumption exceeding 213,000,000 kWhs (DOD Closing Brief at 1).

[135] See Exhibit 8 to the 2008 Settlement Agreement for revised rates LLP-14 and option TOU rate LLP-90N.

tariffs discourage rather than encourage large-scale renewable energy projects. DOD states that the Company is currently conducting workshops on the PRS tariffs and will hopefully have revised tariffs available for Commission consideration by the time the Commission meets to make a decision on the 2008 Settlement Agreement.[136] Further, DOD comments that the new interruptible and demand response tariffs will provide additional demand-reduction tools that will allow customers to respond quickly to TEP requests to reduce demand.

Kroger also fully supports the 2008 Settlement Agreement, and was particularly interested in the design of the TOU rates for commercial customers.[137] Kroger believes the design of the TOU schedules for commercial customers achieves the goals of TOU rates to send prices signals during peak times and to provide an incentive to customers to curtail load during peak times. Kroger argues the decreased usage during peak times benefits all customers as it reduces the need to build or purchase additional capacity.

11. <u>Renewable Energy Adjustor & Demand-Side Management Programs and Adjustor</u>

According to AECC, the REST and DSM Adjustors levied on all retail rate schedules enable the collection of revenues to fund DSM projects and renewable resources.[138] SWEEP, whose position is discussed in greater detail below, is a strong supporter of the DSM Adjustor.

12. <u>Status of TEP's Certificate of Convenience and Necessity ("CC&N")</u>

TEP had originally requested that its CC&N be returned to exclusivity. The 2008 Settlement Agreement provides that CC&N exclusivity issues should be addressed in a generic docket.[139] AECC, in particular, asserted that the resolution of the issue concerning the status of the exclusivity of TEP's CC&N is an important aspect of the 2008 Settlement Agreement.[140] AECC's witness, Mr. Higgins, testified that the unbundled rates provide the option for customers to take service from an alternative provider and the right to avail themselves of the transmission system. Mr. Higgins believed that maintaining the possibility of Direct Access could assist retail customers who are now

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[136] TEP states that it met with interested stakeholders on August 4, 2008 and August 19, 2008, and anticipates filing its PRS Tariff in advance of the Commission's Open Meeting to consider the 2008 Settlement Agreement.
[137] Kroger Brief at 1.
[138] AECC Brief at 7.
[139] 2008 Settlement Agreement Section 12.1.
[140] AECC Brief at 10.

looking at sustainability issues and opportunities for directly availing themselves of renewable energy.[141] He also believed it could act as a check on utilities' requests for rate increases.[142]

Mesquite states the approach preserves the status quo of TEP's CC&N pending such further action on the subject of retail electric competition as the Commission may elect to pursue. Mesquite believes this approach is fully consistent with Decision No. 70485 (September 3, 2008) in which the Commission decided to suspend processing the application of Sempra Energy Solution LLC for an Electric Service Provider CC&N pending the conduct of workshops and a Staff Report on the subject of retail electric competition.

13. Returning Customer Direct Access Charge

The 2008 Settlement Agreement provides that TEP will file, as a compliance item, an RCDAC that will only apply to customers with a demand load of 3 MW or greater who do not provide TEP with one year's advance written notice of intent to return to TEP for Generation and Standard Offer service. TEP asserts that this provision is a benefit of the 2008 Settlement Agreement because it appropriately apportions the costs attributed to a customer that leaves, and then re-establishes service without providing the proper notice, upon that same customer.[143]

14. Rules and Regulations

TEP asserts that the changes and modifications to its Rules and Regulations are an added benefit of the 2008 Settlement Agreement.[144] TEP states that a significant positive change is the elimination of free footage from its line extension tariffs, and notes that no party has objected to any of its proposed modifications.

15. Fuel Audit

TEP asserts that the provision of a fuel audit is a material benefit to customers because it creates a process whereby Staff can evaluate the fuel procurement practices as a further check and balance to ensure that TEP is following prudent fuel procurement practices.[145]

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[141] Tr at 603.
[142] Tr at 604.
[143] Ex TEP-2 Pignatelli Settlement Direct at 22-23.
[144] TEP Brief at 24.
[145] TEP Brief at 25.

B. SWEEP's Position

SWEEP neither supports nor opposes the 2008 Settlement Agreement. SWEEP was primarily concerned with DSM issues, and states it did not have the time or resources to perform the analysis needed to take a position on the 2008 Settlement Agreement as a whole.[146] TEP's DSM programs are being reviewed and approved in a separate docket (Docket No. E-01933A-07-0401) that has been proceeding parallel to the rate proceeding. SWEEP supports the two docket approach and the current schedule of the Commission's review of the DSM programs.[147] SWEEP supports the use of a DSM Adjustor Mechanism for DSM cost-recovery and supports the DSM Adjustor as set forth in the 2008 Settlement Agreement.[148]

SWEEP strongly advocates the implementation of the Commission-approved DSM programs without delay. Based on information that DSM funding currently available in 2008 is approximately $3.3 million, SWEEP believes that there are sufficient funds available to fund the existing and new DSM programs.[149] Consequently, SWEEP believes that an interim DSM cost-recovery mechanism in this rate proceeding is not necessary.[150] However, if customer response to the programs in the latter half of 2008 is very strong and TEP finds that its DSM funding is inadequate, SWEEP would recommend an accounting mechanism to provide interim cost recovery until the DSM Adjustor is adopted by the Commission in this case.[151]

SWEEP also supports the DSM Performance Incentive as clarified in Staff's rebuttal testimony.[152] Under this performance-based incentive mechanism, TEP would have the opportunity to earn up to 10 percent of the measured net benefits from the eligible DSM programs, capped at 10 percent of the actual program spending. SWEEP believes this is an incentive to encourage the achievement of net benefits, with at least 90 percent of the net benefits accruing to customers.[153]

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[146] Tr at 546.
[147] Tr at 540.
[148] Ex SWEEP-2 Schlegal Settlement Direct at 3; Tr at 541.
[149] Ex SWEEP-2 at 3.
[150] Tr at 542.
[151] Ex SWEEP-2 at 3; Tr at 542.
[152] Tr at 543; Ex Staff-8 Keene Rebuttal at 3; Ex Staff-1 Keene Direct at 5.
[153] Ex SWEEP-2 at 4.

SWEEP believes that it is likely that additional funding for Commission-approved DSM programs will be needed prior to 2012.[154] SWEEP believes that DSM spending levels on Commission-approved programs should be able to increase in between rate cases. SWEEP believes that the Commission and Staff could be notified of the DSM program spending increase, and the Commission can choose whether or not to take action on it, however, the spending increase for Commission-approved programs should not require Commission pre-approval or other action by the Commission.[155] SWEEP proposes that if the estimated spending increase is significant, Staff or the Company could notify the Commission of such and request Commission pre-approval of the spending increase.[156]

C. **RUCO's Position**

RUCO believes that the amount of the rate increase under the 2008 Settlement Agreement is too great compared to the benefits ratepayers would receive. RUCO states that it is statutorily charged with looking after the best interests of residential ratepayers, but while this means that RUCO balances its statutory authority with the interests of the Company to maintain financial health, it believes that "the Company should have an opportunity to earn a reasonable return, and not one dime more."[157] RUCO states that it determined early in the settlement process that the gap between the Company's settlement proposal and RUCO's filed position was too wide to reach "common ground." Thus, RUCO believed that it would have been unfair for it to participate in the settlement negotiations knowing RUCO could not be a signatory.

In its underlying case, RUCO recommended an increase over adjusted base year revenues of $36,254,000. RUCO states the 2008 Settlement Agreement provides for a $136.8 million increase, or 19.8 percent, over TEP's adjusted current base rates excluding the Fixed CTC.[158] Furthermore, RUCO estimates that when the rate increase is adjusted for the estimated PPFAC, the 2008 Settlement Agreement provides for a total yearly increase of $146,248,098, or 21.15 percent over

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[154] Ex SWEEP 2 at 3; Tr at 549.
[155] Id.
[156] Tr at 552.
[157] RUCO's Closing Brief at 2.
[158] Ex TEP-1 at 6; Ex RUCO-2 at 7.

adjusted current base rates.[159] RUCO argues the cost to ratepayers from the difference of $109,994,098 between the expected increase under the 2008 Settlement Agreement and RUCO's recommendation is too great for the 2008 Settlement Agreement to be found to be in the public interest. RUCO believes "that after the litigation risks and all other things are considered, if there comes a point when the concessions significantly outweigh the exchanged benefits, then the Settlement is not in the best interests of ratepayers."[160]

1. **Amount of Rate Increase**

RUCO argues the Signatories make too many and too large concessions in exchange for the benefits of the 2008 Settlement Agreement. In particular, RUCO criticizes the concession made to reinstate $99 million related to the FAS 143 write-off of accumulated depreciation.[161] The reduction in accumulated depreciation agreed to in the 2008 Settlement Agreement increases rate base. RUCO argues that ratepayers pay for the retirement of assets through Depreciation Expense, which is reflected in rates, and that reducing accumulated depreciation would be unfair to ratepayers because they are paying for a return on a higher rate base after they had already paid for that plant in their rates. RUCO argues FAS 143 is inappropriate for regulatory accounting because writing off a portion of the accumulated depreciation results in the double recovery of the previously accrued asset retirement costs.[162] RUCO believes that its litigation position on the depreciation issue is well founded and asserts the Commission should modify the proposed Settlement Agreement commensurately to reflect RUCO's view on this issue.[163]

RUCO also criticizes the 2008 Settlement Agreement's concession to reduce accumulated depreciation by $41.6 million attributed to TEP using lower depreciation rates for its generation assets commencing in 2004 than had been approved in the last rate case.[164] The adjustment trues-up the accumulated depreciation balance to the Commission's authorized rates from TEP's last rate case. RUCO believes that its position on this issue would prevail if litigated.

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[159] Ex RUCO-2, Exhibit WAR-1.
[160] RUCO Brief at 6.
[161] In direct testimony Staff recommended an increase in accumulated depreciation of $99 million. RUCO had recommended an increase in accumulated depreciation of $112.8 million. (Ex RUCO-2 at10).
[162] Ex RUCO-2, Rigsby Responsive Testimony at 11.
[163] RUCO Brief at 5.
[164] RUCO Brief at 5.

2. **Assessment of Benefits**

RUCO argues that the purported benefits of the 2008 Settlement Agreement, namely the touted $47.1 million (6 percent) rate increase, the moratorium on base rate increases through 2012, the waiver of claims under the 1999 Settlement Agreement and the implementation of a PPFAC, must be put in perspective. First, RUCO notes, with the application of the PPFAC, ratepayers will see a 9 to 10 percent increase, rather than the 6 percent mentioned in the 2008 Settlement Agreement. RUCO claims that the 2008 Settlement Agreement is misleading, and that the actual rate increase is approximately 21.5 percent which should be made known to the public. RUCO asserts that the attractiveness of a rate moratorium is predicated on the assumption that rates are not set too high to begin with. In RUCO's view, the rates resulting from the 2008 Settlement Agreement are too high to begin with and this negates any benefit of a rate moratorium.

RUCO concludes that a lawsuit brought by TEP over whether generation rates would be set by the market after the rate moratorium expired December 31, 2008, would ultimately be found to lack merit.[165] RUCO notes that Staff and AECC agreed with RUCO that there is no basis for TEP to charge market rates. RUCO points out Staff testified in the Motion to Amend proceeding that "[n]o basis exists for the $844 million of foregone revenues included therein, which TEP alleges to be part of the economic damages that it has sustained due to Arizona's experiment with electric competition."[166] RUCO also cites the testimony of Kevin Higgins for the AECC who concluded in the Motion to Amend proceeding that TEP was not authorized to charge market rates after 2008.[167] RUCO acknowledges there is some litigation risk that TEP would prevail, but concludes the risk to ratepayers from TEP prevailing in its threatened lawsuit does not warrant resolving the issue by settlement.[168]

3. **Structure of PPFAC**

RUCO believes that the proposed PPFAC is overly generous.[169] RUCO states that TEP's generation mix is primarily coal, the cost of which has historically been less volatile than natural gas.

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[165] RUCO Brief at 8.
[166] Direct Testimony of Michael J Ileo filed in Motion to Amend at 6.
[167] Direct Testimony of Kevin Higgins filed in Motion to Amend, Legal Brief at 6.
[168] RUCO Brief at 9.
[169] Id.

RUCO points out that APS, which has a much higher exposure to gas, includes a fuel adjustor with a 4 mil cap and a 90/10 sharing clause. RUCO argues that the proposed PPFAC in the 2008 Settlement Agreement, which has no cap or sharing provision, makes no sense and would result in bad precedent. RUCO has recommended a fuel adjuster that only applies to incremental sales, which it argues is more appropriate for a company with historically less volatile fuel costs than APS. RUCO believes ratepayers would be better off under RUCO's recommendations.

D. Unresolved Issues under 2008 Settlement Agreement

1. Disposition of Fixed CTC True-up Revenues

The 2008 Settlement Agreement did not resolve the issue of how to treat the Fixed CTC True-up Revenue. TEP has estimated that Fixed CTC True-up Revenue will be approximately $66 million by the end of 2008.[170]

Based on Decision No. 69568, which provides that the true-up revenue would accrue interest and be refunded at an appropriate rate of interest, either as a refund or credit to be determined in this docket, Staff recommends that the Fixed CTC True-up Revenue be credited against the PPFAC.[171] The DOD agrees and argues that the over-collection of the Fixed CTC True-up Revenues belongs to the Company's customers.[172] DOD urges the Commission to credit all of the Fixed CTC True-up Revenues to the PPFAC bank account to offset any projected increase in fuel costs in 2009. DOD believes this is consistent with the findings and order of Decision No. 69568, and DOD finds no rationale to support a sharing between the Company and its customers.

AECC recommends that the greater of $32.5 million, or 50 percent of the Fixed CTC True-up Revenues, be credited to customers in the PPFAC balancing account and that TEP be allowed to retain the remainder of the Fixed CTC True-up revenues.[173] AECC believes that an important factor in its recommendation is the fact that when the CTC was established in 1999, it was not a new charge that was added to TEP's existing rates, but rather a "carve out" of the existing rates that was designated for Fixed CTC recovery. Thus, in AECC's view, when the Fixed CTC expired, it did not

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[170] Tr at 112.
[171] Tr at 342.
[172] DOD Brief at 4.
[173] AECC Brief at 9.

remove a charge that was added-on but strips out a pre-existing portion of rates that had previously been determined to be just and reasonable by the Commission.[174] AECC believes that in light of the settlement, and TEP's withdrawal of its claims under the 1999 Settlement Agreement, sharing the Fixed CTC True-up Revenue between customers and the Company is an equitable outcome.[175]

TEP argues that TEP should retain the Fixed CTC True-up Revenues and argues that any refund or credit of the Fixed CTC True-up Revenues would be inequitable and confiscatory.[176] TEP asserts a credit or refund for the Fixed CTC True-up Revenues would aggravate the current inability of TEP to earn a just and reasonable return and would confiscate a portion of revenues that TEP collected through rates that were previously determined to be just and reasonable. TEP argues it has been under-earning since at least 2006, even with the Fixed CTC Revenues included in the revenue requirement calculation. In addition, TEP asserts the Fixed CTC was simply an accounting mechanism that did not increase customer rates, which rates the Commission found to be just and reasonable in Decision No. 62103. TEP argues the Fixed CTC did not increase those rates, but was rather an unbundled element that was delineated to allow retail electric competition.[177] TEP states the Fixed CTC was an accounting mechanism that was intended to allow TEP to amortize $450 million of generation plant stranded costs between 1999 and the end of 2008 rather than incur the entire write-off in a single year.[178] TEP states is did not collect extra revenue from the Fixed CTC, but that it did write down the value of generation assets by $450 million.[179] Third, TEP claims ratepayers are realizing the benefits of the Fixed CTC because the Cost-of-Service generation rates under the 2008 Settlement Agreement reflect the accelerated write-down of $450 of generation assets and given the accounting nature of the Fixed CTC, ratepayers did not pay extra for that benefit. TEP asserts that because TEP's generation rates will be based on Cost-of-Service, ratepayers will receive that benefit in perpetuity. TEP argues this long-term benefit was not contemplated in 1999 and demonstrates why "blind adherence" to the 1999 Settlement Agreement provision concerning

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[174] AECC Brief at 10.
[175] Id.
[176] TEP Brief at 26.
[177] TEP Brief at 27.
[178] Ex TEP-3 Pignatelli Settlement Rebuttal at 7.
[179] Tr at 103.

termination of the Fixed CTC is not appropriate or equitable. As a result, TEP states it is potentially faced with a reduced rate base for its new Cost-of-Service rates and a reduction to its current rates. TEP argues that imposing both reductions effectively double-counts the impact of the $450 million generation asset reduction.

TEP does not believe the other parties have set forth any compelling reason for requiring a credit or refund, and that they do not dispute TEP has been under-earning since 2006, or that the Fixed CTC did not increase rates. In TEP's view, one of the benefits of the 2008 Settlement Agreement is to extinguish all issues and claims related to the 1999 Settlement Agreement, and it is inequitable to allow a select provision of the 1999 Settlement Agreement to transfer economic benefits from TEP to its customers.[180]

AIC supports TEP retaining the Fixed CTC True-up Revenues.[181] AIC argues that as a global matter, the 2008 Settlement Agreement's Section XIV contains nine different provisions that recognize the intended purpose of the 1999 Settlement Agreement "to allow a transition to retail electric competition" has been frustrated. AIC argues these provisions collectively terminate the 1999 Settlement Agreement, and it would be unfair to resuscitate only a small portion of the 1999 Settlement Agreement (i.e. the rate moratorium and the termination of the Fixed CTC), especially when the Company's current rates are not adequate.[182] AIC argues that the CTC Revenues were intended to position the Company to compete in the wholesale market on January 1, 2009, but instead, given the Company's return to Cost-of–Service rate regulation, the write-off of the CTC-related plant value reduces costs, and by extension, customers' rates. AIC argues under the significantly changed circumstances since 1999, there's no reason for another credit to customers on top of the savings they will realize from the rate base write-offs that were financed by the CTC Revenues. Furthermore, AIC argues, because the Commission has determined TEP's current rates, which include a portion attributable to CTC, to be just and reasonable, there is no rationale or equity in returning a portion of these rates to customers.[183]

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[180] TEP Brief at 29.
[181] AIC Brief at 6-7.
[182] AIC Brief at 6.
[183] Id.

2. Effective Date of Rate Increase

Staff and AECC argue that the new rates should become effective on January 1, 2009, as was contemplated by Decision No. 62103. Staff asserts there is no language in the 2008 Settlement Agreement that extinguishes or supersedes the 1999 Settlement Agreement. AECC states January 1, 2009 is the most appropriate date as it corresponds to the expiration of the rate cap established in the 1999 Settlement Agreement.

TEP, AIC and IBEW believe that new rates should be implemented at the earliest possible date.[184] TEP believes there is no reason to delay implementation of the new rates to cling to a legacy of the 1999 Settlement Agreement, which agreement TEP argues is superseded by the 2008 Settlement Agreement.[185] TEP states that it has been under-earning since at least the 2006 test year and delaying implementation of the new rates interferes with TEP's opportunity to earn a just and reasonable return. Furthermore, it asserts, it needs those revenues to continue to operate a safe and reliable electric system and to meet significant capital expenditure requirements. TEP believes the time and context of the 1999 Settlement Agreement has passed. In addition, TEP asserts that any delay in rate relief will exacerbate the scope of the Fixed CTC True-up Revenue dilemma. Finally, TEP asserts there are important rates and programs that should go into effect sooner rather than later, such as the new TOU rates.[186]

AIC asserts that implementing the new rates as soon as possible is consistent with the Commission's statement in Decision No. 69568 that "it is in the public interest to evaluate and approve new rates for TEP as quickly as is practical . . ." Furthermore, AIC argues the Signatories have concluded that TEP has been under-earning since 2006.

DOD does not object to the implementation of new rates prior to January 1, 2009.

RUCO appears to believe that the failure of the 2008 Settlement Agreement to resolve all outstanding issues in this case, is a weakness of the settlement. According to RUCO, the open issues of how to treat the true-up of the Fixed CTC Revenues and the date when the new rates become effective could have a substantial impact on customer bills. RUCO states the ultimate resolution of

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[184] Tr at 420; Tr at 470; Tr at 448.
[185] TEP Brief at 30.
[186] TEP Brief at 31.

these issues could significantly change the balance between the costs and the benefits of the settlement.

IV. Analysis and Resolution

We find that the proposed 2008 Settlement Agreement results in just and reasonable rates and is in the public interest and should be adopted. It was negotiated in discussions that were open to all interested parties. All parties were notified of the settlement process and invited to participate. No party stated they were not given an opportunity to participate. We believe the process resulted in a fair and balanced agreement that provides benefits to ratepayers, employees and shareholders. RUCO is the only party to this docket who opposes the 2008 Settlement Agreement. RUCO's primary opposition is the amount of the rate increase and the structure of the PPFAC. Even RUCO acknowledges the 2008 Settlement Agreement is not without redeeming provisions and contains a number of benefits for ratepayers that RUCO supports, including expanded TOU tariffs, expanded DSM programs and spending, the four year base rate moratorium, the equitable rate spread, holding low income ratepayers harmless from the increase in base rates and the PPFAC, customer credits for short-term sales revenues, the credit for 10 percent of wholesale trading profits, and customer credit for 50 percent of the revenues realized from the sale of SO2 emission allowances.[187] RUCO also supports the adjuster clauses for DSM and renewable energy programs. [188]

The 2008 Settlement Agreement results in a base rate increase of $136.8 million. In its pre-settlement testimony, TEP proposed a revenue increase of $275.8 million under its Cost-of-Service methodology, which included an approximate $158.2 million increase in base rates and $117.6 million for its requested "Transition Cost Regulatory Asset Charge", which TEP had requested as a separate surcharge.[189] Staff had recommended a revenue increase of approximately $9.7 million.[190] RUCO had recommended a $36.2 million increase which was calculated after excluding the Fixed CTC revenues.[191] The procedural schedule was suspended before Staff and Intervenors filed their surrebuttal testimony. During the hearing, Staff testified that had Staff filed surrebuttal testimony it

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[187] Tr at 934.
[188] Tr at 949 - 950.
[189] Ex Staff -4, Smith Settlement Direct, at 3.
[190] Ex Staff-4 at 4 & Ex 2 to 2008 Settlement Agreement.
[191] Ex RUCO-2 at 8.

would have revised its recommended revenue requirement higher, to somewhere between $60 and $70 million.[192] While we express no opinion on how we might otherwise resolve pre-settlement disputes concerning depreciation and the costs of the Springerville lease, among others, based on the testimony in this proceeding, we find that the revenue increase under the 2008 Settlement Agreement is reasonable when viewed in conjunction with the other benefits of the agreement. We do not agree with RUCO that the costs of the ratepayer benefits under the agreement come at too high a price. Nor do we find the 2008 Settlement Agreement to be deceptive. The revenue increase in base rates, whether compared to existing rates with or without the Fixed CTC is reasonable and fair. The evidence indicates that under the 2008 Settlement Agreement, the average residential customer using 900 kWhs/month would experience a base rate increase of 3.2 percent, from $84.55 to $87.25, and that the PPFAC and DSM surcharge would add an additional 4.9 percent. Ten percent of TEP's customers account for 27 percent of residential usage.[193] The proposed rate structure would impose a moderate increase on the average residential energy user, while imposing a greater percentage increase on those who use disproportionately more energy. The increase we approve will allow TEP to continue to provide safe and reliable service, while sending more accurate and fair price signals to users.

The benefits of the 2008 Settlement Agreement are numerous and some would likely have been difficult to obtain without a consensual resolution. In particular, the provision that protects low income ratepayers from both the increase in base rates and the effect of the PPFAC is innovative and unprecedented in Arizona. The 6 percent across-the-board allocation of the base rate increase, when there is some evidence that a cost of service study might support a greater increase for residential customers, is also a benefit to residential ratepayers. The negotiated rate design offers improved TOU tariffs that will permit ratepayers the opportunity to mitigate the effect of the increase. The large users, as represented in this proceeding by AECC and DOD are particularly supportive of the rate design that will encourage load shifting, and are encouraged that progress will finally be made in the partial requirements tariffs that will promote the installation of large renewable distributed

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[192] Tr at 493.
[193] Ex TEP-6, Dukes Settlement Direct at 6.

generation projects.[194]

Further, the 2008 Settlement Agreement resolves the FAS No. 143 issue without causing TEP to write-down assets which could detrimentally affect its financial condition. Since the 1999 Settlement Agreement, the Company has been able to build its equity. Given the current uncertain financial climate in this country, and uncertainty over future carbon taxes, maintaining and increasing TEP's equity is important. By enabling TEP to avoid write-offs, the 2008 Settlement Agreement will benefit TEP's capital structure, without substantially burdening ratepayers. Ratepayers benefit from a strong capital structure because the Company is able to attract capital at better prices.

Under the 2008 Settlement Agreement, the parties were able to agree that TEP would be regulated pursuant to the Cost-of-Service methodology, and TEP agreed to forgo its claim of damages from a return to Cost-of-Service regulation. We cannot diminish the public benefit of determining with finality, and without litigation, that TEP's generation assets will be subject to Cost-of-Service regulation on a going-forward basis. RUCO argued in the hearing that it was confident that its position that TEP had no claim for damages under a return to Cost-of-Service would ultimately prevail, but we cannot say that TEP's initial position was frivolous or had no chance of prevailing. Even if RUCO's and Staff's pre-settlement positions would have prevailed, there is a public benefit to avoiding the time and expense of litigation. Ratepayers and shareholders benefit from the certainty and finality that result from the consensual resolution of the Cost-of-Service issue and TEP's claims for damages under the 1999 Settlement Agreement.

We find too that the PPFAC as set forth in the 2008 Settlement Agreement is fair and reasonably designed to permit TEP to recover the volatile costs of its purchased power and fuel used to supply retail electric power. Although it does not contain a cap or 90/10 sharing arrangement, it contains the added protection that the PPFAC will not be modified except by Commission order. Each year the Commission will be able to consider the effects of a potentially disruptive spike in fuel costs in the context of current events, which allows the Commission to determine the best course of action at the time, instead of relying on a cap that may or may not protect ratepayers. A cap that is

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[194] SWEEP proposed some sort of banded DSM mechanism in order to ensure adequate DWM funding. The evidence in this docket is not sufficiently developed to allow us to determine at this time if such proposal is in the public interest.

too high is ineffective, and a cap that is too low, may result in larger cost deferrals that could aggravate the intended purpose of the cap to shield ratepayers. Although the Commission adopted a 90/10 sharing arrangement in connection with APS's fuel adjustor, no party, except maybe RUCO, advocated such provision in this case. Mr. Smith and Mr. Hutchens testified that the problem with a 90/10 sharing arrangement is that when prices are falling, ratepayers do not receive the full benefit of the decline.[195] Even RUCO did not provide evidence of benefits that would support such sharing arrangement. The PPFAC adopted in this case is designed specifically for TEP and the circumstances existing at the time of its adoption, and we do not believe that it should serve as precedent, except as an example of how such adjustor might be designed, in any other case.

We believe that the Fixed CTC True-up Revenues should be credited in their entirety to the ratepayers by means of a credit to the PPFAC. Decision No. 69568, in which the Commission determined to keep the Fixed CTC in place, provided "that the incremental revenue collected as a result of retaining the Fixed CTC and maintaining Standard Offer rates at their current level shall be treated as 'True Up Revenue' as discussed herein, and shall accrue interest and shall be subject to refund, credit or other mechanism to protect customers as determined by the Commission in the forthcoming rate case docket." We agreed to suspend the termination of the Fixed CTC in the Motion to Amend proceeding at the request of TEP which was very concerned about its cash flow position.[196] Our concern in Decision No. 69568 was to balance the Company's concern about its financial condition while protecting ratepayers. By adopting the 2008 Settlement Agreement, which provides TEP with increased base rates and a PPFAC, and returning the Fixed CTC true-up revenues to the ratepayers, we believe we are accomplishing both goals of Decision No. 69568. Furthermore, when the Commission found TEP's current rates in Decision No. 62103 to be just and reasonable, it made that determination with the knowledge that the Fixed CTC would terminate after it collected $450 million. Thus, contrary to the arguments of TEP and AIC, the current rates that have been found to be just and reasonable include the termination of the Fixed CTC component, and we do not find it determinative that the Fixed CTC was not an "add on" to the previously existing rates.

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[195] Tr at 789 & 842.

[196] See Transcript of March 8, 2007 in Motion to Amend at 591-611.

Finally, we believe that the 2008 Settlement Agreement should be effective as of the first of the month following Commission approval. The Company can begin collecting increased revenue from its increased base rates and any detriment from another month of collecting Fixed CTC True-up revenue will be avoided, and ratepayers can take advantage of TOU rates and restructured demand charges.

V. TEP Request for Commission Authorization to Defer Unrealized Gains and Losses

TEP states that upon Commission approval of the 2008 Settlement Agreement TEP will apply FAS 71 to its generation operations, and that with approval of the PPFAC, TEP would record the change in fair market value (unrealized gains and losses) of resource acquisition agreements defined as derivatives under FAS No. 133, Accounting for Derivative Instruments, as deferred assets or liabilities in FERC Account No. 186, "Miscellaneous Deferred Debts", and FERC Account No. 252, "Other Deferred Credits", in accordance with FAS No. 71, *Accounting for the Effects of Certain Types of Regulation*.[197] TEP seeks an Accounting Order similar to the one the Commission approved for UNS Electric, Inc. in Decision No. 69202 (December 21, 2006). TEP proposes an accounting treatment which it states would have no effect on the cost of power, and would not impact the PPFAC mechanism. TEP states it would not seek rate base treatment of the requested FAS No. 133 deferral accounts, nor cost recovery of any amounts.[198]

TEP did not raise this issue prior to filing its Closing Brief. It does not appear controversial, but we believe it is not appropriate to address it without giving Staff and other interested parties an opportunity to comment on the proposal. TEP should file an Application to address this issue, which we trust Staff will process in a timely fashion.

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Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

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[197] TEP Brief at 18.
[198] TEP Brief at 19.

FINDINGS OF FACT

1. Pursuant to Decision No. 69568,[199] on July 2, 2007, TEP filed a rate application in Docket No. E-01933A-07-402; a DSM Portfolio in Docket No. E-01933A-07-0401; and a Renewable Energy Action Plan in Docket No. R-01933A-07-0400. Docket Nos. E-01933A-07-0402 and E-01933A-05-0650 were consolidated.

2. The 2007 Rate Application proposed three alternative rate methodologies: (i) the Market Methodology, (ii) the Cost of Service Methodology, and (iii) the Hybrid Methodology. TEP proposed a base rate increase of $267.57 million (a 21.9 percent increase) under the Market Methodology; an increase of $275.80 (23 percent) under the Cost-of-Service Methodology, comprised of a $158.20 million base rate increase and an additional $117.60 million for a TCRAC; and a base rate increase of $212.54 million (14.9 percent) under the Hybrid Methodology. The dollar amounts of the proposed base rate increases excluded DSM charges and the Fixed CTC. The percentage increases are calculated based on TEP's 2006 test year revenue that included DSM and the Fixed CTC revenue.

3. The following entities were granted intervention in the consolidated dockets: AECC, DOD, RUCO, AIC, IBEW, Mesquite, Kroger, SWEEP, WRA, APS, the Alliance; SSVEC, Ms. Cynthia Zwick, a member of the Arizona Community Action Association, and TEP residential customers Mr. Billy Burtnett and Mr. John O'Hare.

4. On February 29, and March 14, 2008, Staff, RUCO, DOD, AECC, Kroger and Mesquite filed their direct testimony in the consolidated dockets.

5. Staff, RUCO and AECC proposed utilizing a Cost-of-Service methodology and proposed new base rates for TEP. Staff proposed a base rate increase of $9.77 million over TEP's 2006 test year adjusted revenues, which excluded Fixed CTC and DSM revenues. Staff's base rate recommendation excluded the impact of the DSM, REST and PPFAC adjustors. AECC proposed a base rate increase not to exceed $91.62 million using the same baseline as Staff. RUCO proposed a base rate increase of $36.24 million. Staff, RUCO and AECC opposed TEP's proposed TCRAC.

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[199] Docket No. E-01933A-05-0650.

6. On April 1, 2008, TEP filed its Rebuttal Testimony.

7. On April 3, 2008, TEP filed a notice of settlement discussions, inviting all parties to attend settlement discussions. The parties to the proceeding held settlement discussions and subsequently, given those discussions, on April 18, 2008, Staff filed a motion to postpone the filing of Surrebuttal testimony.

8. By Procedural Order dated April 21, 2008, Staff's request was granted and the further filing of testimony was suspended pending the outcome of settlement discussions.

9. On April 23, 2008, TEP filed a notice that it and Staff had reached an agreement in principle on the terms of a settlement. A Procedural Order dated May 1, 2008, set a Procedural Conference on May 8, 2008, to set a schedule and determine a process for considering the settlement.

10. By Procedural Order dated May 12, 2008, a schedule for filing the settlement agreement and testimony in support or opposition was established, and the hearing on the proposed settlement was set to commence on July 9, 2008.

11. On May 12, 2008, (the date that had been noticed for the hearing on the 2007 Rate Application) the Commission convened for the purpose of taking public comment. Representatives of the City of Tucson and the Arizona Solar Alliance appeared to make public comment. In addition, the Commission received approximately 13 emails, calls, or written comments from consumers opposed to a rate increase. At the beginning of the July 9, 2008 hearing, representatives of the Pima County Community Action Agency and the City of Tucson appeared to make public comment. In addition, the Commission received an emailed comment specifically addressing the terms of the settlement.

12. On May 29, 2008, Staff filed a copy of the 2008 Settlement Agreement executed by TEP, Staff, AECC, ACAA, DOD, AIC, IBEW, Mesquite and Kroger.

13. RUCO attended a number of the settlement discussions, but did not participate in discussions and did not sign the 2008 Settlement Agreement. SWEEP also did not execute the 2008 Settlement Agreement, but indicated that it does not oppose it.

14. On June 11, 2008, TEP, Staff, Mesquite, Kroger, DOD, AECC, Ms. Zwick and AIC filed direct testimony or comments in support of the proposed 2008 Settlement Agreement. IBEW

obtained an extension, and filed its testimony in support of the 2008 Settlement Agreement on June 19, 2008.

15. On July 2, 2008, RUCO filed testimony in opposition to the 2008 Settlement Agreement. On the same date, SWEEP filed its testimony commenting on the settlement.

16. On July 7, 2009, TEP filed rebuttal testimony in support of the 2008 Settlement Agreement.

17. The hearing convened before a duly authorized Administrative Law Judge as scheduled on July 9, through July 16, 2008, at the Commission's office in Tucson, Arizona.

18. On August 29, 2008, TEP, Staff, RUCO, DOD, AECC, Mesquite, Kroger, SWEEP and AIC filed Closing Briefs. The IBEW and Ms. Zwick did not file Closing Briefs.

19. A copy of the 2008 Settlement Agreement is attached hereto as Exhibit "A". The terms of the 2008 Settlement Agreement are more fully described in the Discussion section of this Order, but include *inter alia*, the following provisions:

(a) An increase in base rate revenues of $47.1 million, from $781.1 million in the 2006 test year to $828.2 million, including the Fixed CTC Revenues in test year revenues, but excluding DSM and RES revenues.

(b) An increase of $136.8 million over test year 2006 base rate revenues when the Fixed CTC is not included.

(c) That TEP's rates will be based on a Cost-of-Service Methodology, with the Springerville Unit 1 and Luna Generating Station included at original cost; and recovery of Springerville Unit 1 non-fuel costs to be recovered at $25.67 per kW per month.

(d) A fair value rate base of $1,451,558,000 and fair value rate of return of 5.64 percent.

(e) A capital structure comprised of 57.5 percent debt and 42.5 percent equity, a return on common equity of 10.25 percent, and embedded cost of debt of 6.38 percent.

(f) Adopts a PPFAC that includes a forward component and true-up component and will be reset annually on April 1st of each year upon Commission Order.

(g) Protects low income rate payers from the base rate increase and the effect of the

PPFAC.

(h) Establishes inclining block rates, TOU tariffs and tariffs for larger customers that encourage energy conservation and/or load shifting.

(i) Establishes a REST Adjustor Mechanism and DSM Adjustor Mechanism.

(j) Provides for a base rate moratorium through January 1, 2013.

(k) Retains the current status of TEP's CC&N exclusivity.

(l) Provides for a RCDAC to recover from Direct Access customers the additional costs that these customers would impose on other Standard Offer customers if and when they return to Standard Offer service.

(m)TEP agrees to forego all claims relating to the 1999 Settlement Agreement or Decision No. 62103, including any claim to damages.

20. The 2008 settlement Agreement provides that it is in the public interest that TEP's rates be determined by a Cost-of-Service methodology until future Order of the Commission. The rate making treatment of TEP's generation assets as set forth in the 2008 Settlement Agreement is fair and reasonable and in the public interest.

21. TEP's fair value rate base is $1,451,558,000, and a 5.64 percent fair value rate of return is reasonable and appropriate.

22. It is just and reasonable to authorize an annual base rate increase in the amount of $47.1 million, or 6.0 percent, from $781.1 million in the test year to $828.2 million (when the Fixed CTC Revenues are included in test year revenues). When the test year revenues are adjusted to remove the Fixed CTC Revenues, the increase is $136.8 million, or 19.8 percent, from $691.5 million to $828.2 million.[200]

23. Under rates and charges established in the 2008 Settlement Agreement, the average residential customer using 900 kWhs/month would experience a base rate increase of 3.2 percent, from $84.55 to $87.25. The PPFAC[201] and DSM surcharge would add an estimated additional 4.9 percent, or $4.14, resulting in an estimated overall increase of $6.84, or 8.1 percent, from $84.55 to

[200] The dollar and percent amounts of the base rate increase is set forth in Section II of the 2008 Settlement Agreement.
[201] Based on TEP's hypothetical PPFAC based on estimates at the time of the hearing.

$91.37. Because of the inclining block rate structure, customers using more energy will experience a higher percentage increase.

24. The PPFAC as set forth in the 2008 Settlement Agreement is in the public interest. The PPFAC will initially be set at zero and will be re-set annually pursuant to the procedures established in the 2008 Settlement Agreement only after a Commission Order.

25. The ratemaking treatment as set forth in the 2008 Settlement Agreement of Depreciation and Cost of Removal is reasonable.

26. The Cost Recovery Asset of $14,212,843 as set forth in the 2008 Settlement Agreement represents costs that TEP has incurred under the 1999 Settlement Agreement. No party objected to the ratemaking treatment of this asset under the 2008 Settlement Agreement.

27. The REST Adjustor and DSM Adjustor established in the 2008 Settlement Agreement are in the public interest.

28. The inclining block rate structure, TOU rates and other rate design changes as set forth in the 2008 Settlement Agreement will promote energy conservation and beneficial load shifting.

29. No Signatory will seek any change to TEP's base rates that would take effect prior to January 1, 2013 and TEP shall not submit a rate application sooner than June 30, 2012 nor use a test year earlier than December 31, 2011.

30. Upon approval of the 2008 Settlement Agreement, TEP foregoes all claims related in any way to the 1999 Settlement Agreement and/or Decision No. 62103 and TEP will not seek to recover in this, or any subsequent proceeding, any amount that it claims is attributable to its alleged damages related to setting its rates under Cost-of-Service ratemaking principles.

31. The 2008 Settlement Agreement resolves all issues raised in these dockets in a manner that comports with and promotes the public interest. We find that the terms and conditions of the 2008 Settlement Agreement are just and reasonable and the agreement should be approved.

32. The 2008 Settlement Agreement does not resolve the issue of the Fixed CTC True-up Revenues. Decision No. 69568, in which the Commission determined to keep the Fixed CTC in place, provided "that the incremental revenue collected as a result of retaining the Fixed CTC and maintaining Standard Offer rates at their current level shall be treated as 'True Up Revenue' as

discussed herein, and shall accrue interest and shall be subject to refund, credit or other mechanism to protect customers as determined by the Commission in the forthcoming rate case docket." It is fair and reasonable that the Fixed CTC True-up Revenues be credited in their entirety to the ratepayers by means of a credit to the PPFAC.

33. It is fair and reasonable that rates and charges set forth in the 2008 Settlement Agreement become effective for all service provided on or after the first of the month following Commission approval, or January 1, 2009, whichever is earlier.

34. In its Closing Brief, TEP requested an accounting order related to its PPFAC and FAS No. 133. TEP should file an Application for an Accounting Order to address this issue.

CONCLUSIONS OF LAW

1. TEP is a public service corporation within the meaning of Article XV of the Arizona Constitution and A.R.S. §§ 40-222, 250, 251, and 252.

2. The Commission has jurisdiction over TEP and the subject matter of the application.

3. Notice of the application was provided in accordance with the law.

4. The 2008 Settlement Agreement resolves all matters raised in Docket Nos. E-01933A-07-0402 and E-01933A-05-0650 in a manner that is just and reasonable, and promotes the public interest.

5. The fair value of TEP's rate base is $1,451,558,000, and 5.64 percent is a reasonable fair value rate of return on TEP's rate base.

6. The rates, charges and conditions of service established herein are just and reasonable.

ORDER

IT IS THEREFORE ORDERED that the Tucson Electric Power Proposed Rate Settlement Agreement filed in this matter on May 29, 2008, and attached hereto as Exhibit A, is approved.

IT IS FURTHER ORDERED that the 2008 Settlement Agreement shall be effective for all service rendered on and after December 1, 2008.

IT IS FURTHER ORDERED that Tucson Electric Power Company is authorized and directed to file no later than November 30, 2008, revised schedules of rates and charges consistent with this Order.

IT IS FURTHER ORDERED that Tucson Electric Power Company shall notify its affected customers of the approved rates and charges authorized herein by means of an insert in its next regularly scheduled billing and by posting on its website, in a form acceptable to the Commission's Utilities Division Staff. The notice shall include a description of the full rate impact on customers as a result of the 2008 Settlement Agreement, and shall include all applicable surcharges and may include information regarding other relevant terms of the agreement.

IT IS FURTHER ORDERED that Tucson Electric Company shall implement a customer education program explaining how the PPFAC and TOU rates will work and shall maintain on its website information explaining the billing format, rates and charges, including up-to-date information about the PPFAC.

IT IS FURTHER ORDERED that the Fixed CTC True-up Revenues, resulting from Decision No. 68568 shall be credited against the PPFAC.

IT IS FURTHER ORDERED that Tucson Electric Power Company shall file for approval as compliance items in this docket, within 90 days of the effective date of this Decision, a RCDAC tariff, new Partial Requirements Tariffs, an Interruptible Tariff, a Demand Response Program Tariff, and a Bill Estimation Tariff as set forth in the 2008 Settlement Agreement.

IT IS FURTHER ORDERED that to the extent any provision of the 1999 Settlement Agreement or Decision No. 62103 are inconsistent with the 2008 Settlement Agreement or this Order, the former shall be amended to be consistent with the this Order.

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IT IS FURTHER ORDERED that Tucson Electric Power Company shall file an Application for an Accounting Order to address the issues it raises in its Brief regarding FAS No. 133.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN COMMISSIONER

COMMISSIONER COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I, BRIAN C. MCNEIL, Executive Director of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this ______ day of _______, 2008.

BRIAN C. MCNEIL
EXECUTIVE DIRECTOR

DISSENT ____________________________

DISSENT ____________________________

SERVICE LIST FOR: TUCSON ELECTRIC POWER COMPANY

DOCKET NOS: E-01933A-07-0402 and E-01933A-05-0650

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EXHIBIT A

TUCSON ELECTRIC POWER COMPANY

PROPOSED RATE SETTLEMENT AGREEMENT

DOCKET NO. E-01933A-07-0402
DOCKET NO. E-01933A-05-0650

MAY 29, 2008

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Exhibit 1 - Computation of Increase in Gross Revenue Requirements (Calculation of Fair Value Rate Base and Fair Value Rate of Return Revenue Increase)

Exhibit 2 - Comparison of Adjustments to ACC Jurisdictional Revenue Requirement (Original Cost Rate Base, Operating Revenue and Operating Expenses)

Exhibit 3 - Proof of Revenue

Exhibit 4 - Calculation of Base Cost of Fuel and Purchased Power

Exhibit 5 - Depreciation Rates

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PROPOSED SETTLEMENT
OF
ARIZONA CORPORATION COMMISSION
DOCKET NOS. E-01933A-07-0402 and E-01933A-05-0650

The purpose of this agreement ("Agreement") is to settle disputed issues related to Docket No. E-01933A-07-0402, Tucson Electric Power Company's application to increase rates, and Docket No. E-01933A-05-0650, Tucson Electric Power Company's motion to amend Decision No. 62103. This Agreement is entered into by the following entities:

Tucson Electric Power Company ("TEP")
Arizonans for Electric Choice and Competition and Phelps Dodge Mining Company (collectively, "AECC")
Arizona Community Action Association ("ACAA")
U.S. Department of Defense and all other Federal Executive Agencies ("DOD")
Arizona Investment Council ("AIC")
International Brotherhood of Electric Workers Local 1116 ("IBEW 1116")
Mesquite Power, LLC, Southwestern Power Group II, LLC, Bowie Power Station, LLC, and Sempra Energy Solutions, LLC ("Power Producers")
Kroger Company
Arizona Corporation Commission Utilities Division ("Staff")

These entities shall be referred to collectively as "Signatories"; a single entity shall be referred to individually as a "Signatory." The following terms and conditions comprise the Signatories' Agreement.

I. BACKGROUND.

1.1 In 1999, TEP, AECC, ACAA, and the Residential Utility Consumer Office ("RUCO") entered into a Settlement Agreement (the "1999 Initial Settlement Agreement") regarding various issues arising out of the Electric Competition Rules, enacted by the Arizona Corporation Commission ("Commission") as A.A.C. R14-2-1601, et. seq. The 1999 Initial Settlement Agreement, among other things, provided for (i) the commencement of retail electric competition in TEP's service territory; (ii) TEP to recover stranded costs; (iii) the resolution of litigation related to the Commission's Electric Competition Rules; (iv) implementation of two rate reductions; and (v) a freeze on rate increases until December 31, 2008 (the "rate freeze").

1.2 In Decision No. 62103 (November 30, 1999), the Commission modified and approved the 1999 Initial Settlement Agreement. Thereafter, on December 28, 1999, the parties filed an amended, final Settlement Agreement (the "1999 Settlement Agreement"), reflecting the changes made by the Commission.

1.3 On September 12, 2005, TEP filed a Motion to Amend Decision No. 62103 (the "Motion to Amend"). The Motion to Amend sought resolution of a dispute that had arisen over how TEP's generation rates should be determined beginning January 1, 2009.

1.4 In Decision No. 69568 (May 21, 2007), the Commission ordered (i) TEP to file rate proposals by July 2, 2007, to be effective after the termination of the rate freeze, thereby initiating a Rate Proposal Docket; (ii) that the Rate Proposal Docket be consolidated with the Motion to Amend; (iii) that the operation of TEP's Fixed Competition Transition Charge ("Fixed CTC"), established under the 1999 Settlement Agreement, be extended, subject to credit, refund, or other mechanism, until the effective date of the Commission's final Order in the Rate Proposal Docket; and (iv) TEP to file a detailed DSM Portfolio and Renewable Energy Action Plan in separate dockets by July 2, 2007.

1.5 On July 2, 2007, TEP filed (i) a rate application in Docket No. E-01933A-07-0402 ("2007 Rate Application"); (ii) a DSM Portfolio in Docket No. E-01933A-07-0401; and (iii) a Renewable Energy Action Plan in Docket No. E-01933A-07-0400. Thereafter, the 2007 Rate Application and Motion to Amend dockets were consolidated, and the Renewable Energy Action Plan was superseded by the TEP Renewable Energy Standard & Tariff Implementation Plan, approved as modified by the Commission in Decision No. 70314 (April 28, 2008).

1.6 The 2007 Rate Application proposed three alternative rate methodologies: (i) the Market Methodology, (ii) the Cost of Service Methodology, and (iii) the Hybrid Methodology. TEP proposed a base rate increase of $267.57 million or 21.9% for the Market Methodology; an increase of $275.80 million or 23% increase for the Cost of Service Methodology, including a $158.20 million base rate increase and an additional $117.60 million for a "Transition Cost Regulatory Asset" surcharge ("TCRAC"); and a base rate increase of $212.54 million or 14.9% for the Hybrid Methodology. The dollar amounts are for base rate increases on 2006 test year adjusted revenues that exclude DSM and the Fixed CTC. The percentage increases listed above are from TEP's 2006 test year revenue that includes DSM and the Fixed CTC revenue.

1.7 On February 29 and March 14, 2008, Staff and Intervenors filed their direct testimony in the consolidated dockets. Staff, RUCO, and AECC each proposed establishing new base rates for TEP using cost of service. Staff proposed a base rate increase of $9.77 million from TEP's 2006 test year adjusted revenues that excluded DSM and Fixed CTC. RUCO proposed a base rate increase of $36.24 million. AECC proposed a base rate increase not to exceed $91.62 million measured from the same baseline as proposed by Staff that excluded DSM and fixed CTC.

1.8 TEP's average retail rate of approximately 8.4 cents/kWh during the 2006 test year includes revenue for the collection of Fixed CTC. The Staff and RUCO base rate recommendations would have resulted in decreases from the Company's 2006 average retail rate of 8.4 cents/kWh, which includes revenue from the Fixed CTC. Staff, RUCO, and AECC each opposed TEP's TCRAC recommendation.

1.9 On April 1, 2008, TEP filed its rebuttal testimony.

1.10 On April 3, 2008, TEP filed a notice of settlement discussions with the Commission's Docket Control center. The parties to the proceeding subsequently held settlement discussions.

1.11 On April 18, 2008, Staff filed a motion with the Commission requesting the postponement of its surrebuttal testimony. On April 22, 2008, the Administrative Law Judge granted the request, and among other things, suspended the filing of testimony in this matter.

1.12 On or before May 29, 2008, the Signatories entered into this Agreement.

1.13 The settlement discussions were open, transparent, and inclusive of all parties to Docket Nos. E-01933A-07-0402 and E-01933A-05-0650 who desired to participate. All parties to those dockets were notified of the settlement discussion process, were encouraged to participate in the negotiations, and were provided with an equal opportunity to participate.

1.14 The purpose of this Agreement is to settle all issues presented by Docket Nos. E-01933A-07-0402 and E-01933A-05-0650 in a manner that will promote the public interest. The Signatories agree that the terms of this Agreement are just, reasonable, fair, and in the public interest in that they, among other things, (i) establish just and reasonable rates for TEP's customers; (ii) promote the convenience, comfort, and safety, and the preservation of the health, of the employees and patrons of TEP; (iii) resolve the issues arising from the consolidated dockets; and (iv) avoid unnecessary litigation expense and delay.

1.15 The Signatories desire that the Commission issue an order (i) finding that the terms and conditions of this Agreement are just and reasonable, together with any and all other necessary findings; (ii) concluding that the Agreement is in the public interest; (iii) granting approval of the Agreement; and (iv) ordering that the Agreement and its terms be effective upon Commission approval.

II. RATE INCREASE.

2.1 For ratemaking purposes, and in accordance with the terms of this Agreement, the Signatories agree that the fair value of TEP's Arizona jurisdictional rate base for the test year ending December 31, 2006 (the "test year") is $1,451,558,000, as set forth on Exhibit 1. For ratemaking purposes and for the purposes of this Agreement, the Signatories agree that a reasonable fair value rate of return is 5.64%, as shown on Exhibit 1. For ratemaking purposes and in accordance with the terms of this Agreement, the Signatories agree that TEP's jurisdictional revenue deficiency is approximately $136.8 million, as shown on Exhibit 1. The Signatories agree that the opportunity to recover the revenue deficiency results in just and reasonable rates for TEP for the period of the rate moratorium described in Paragraph 10.1. The agreements set forth herein regarding the quantification of fair value rate base, fair value rate of return, and the revenue deficiency are made for purposes of settlement only and should not be construed as admissions against interest or waivers of litigation positions related to any other cases.

2.2 TEP's rates, including its generation rates, will be determined using a cost-of-service methodology. Upon the Commission's issuance of a final, non-appealable order approving this Agreement, TEP shall withdraw its proposed market and hybrid rate methodologies.

2.3 The Signatories agree to an annual base rate increase for TEP of approximately six percent (6%) over the current average rate of 8.4 cents per kWh. This approximate six percent (6%) increase does not include the adjustors for Purchased Power and Fuel, Demand-Side Management, and Renewable Energy. The new average retail base rate will be 8.9 cents per kWh. The approximate six percent (6%) increase, calculated on TEP's existing base rates which include revenue for Fixed CTC, is approximately $47.1 million, and increases TEP's existing base revenue from approximately $781.1 million to $828.2 million. The effect of designing rates to recover $828.2 million is a 6.03% increase.

2.4 The Signatories agree that this increase is just and reasonable. This rate increase is based on the fair value rate base and fair value rate of return set forth on Exhibit 1 and upon the original cost rate base, operating revenue, and operating expenses and adjustments thereto shown on Exhibit 2. As shown on Exhibits 1 and 2, the settlement provides for base rate revenues of approximately $828.2 million, which is a base rate increase of approximately $136.8 million over TEP's adjusted current base rates without Fixed CTC of $691.5 million.

2.5 The rates set forth in the Proof of Revenue, attached hereto as Exhibit 3 and incorporated herein, are designed to permit TEP to recover an additional $47.1 million in base revenues as compared to existing test year base revenues (including Fixed CTC but excluding DSM) of $781.1 million.

III. RATEMAKING TREATMENT OF TEP'S GENERATION ASSETS AND FUEL COSTS.

3.1 For ratemaking purposes, Springerville Unit 1 and the Luna Generating Station shall be included in TEP's rate base at their respective original costs. All other generation assets acquired by TEP after December 31, 2006, but before December 31, 2012, shall be included in TEP's rate base at their respective original costs, subject to the Commission's subsequent regulatory and ratemaking review and approval. This provision is not intended to create a presumption in favor of generation, and the Signatories acknowledge that TEP is obligated to consider all reasonable alternatives when evaluating how to meet its service obligations to its customers.

3.2 Recovery of Springerville Unit 1 non-fuel costs shall reflect a cost of $25.67 per kW per month which approximates the levelized cost of Springerville Unit 1 through the remainder of the primary lease term for this generating facility. In addition, Springerville Unit 1 leasehold improvements shall be included in TEP's original cost rate base at net book value as of December 31, 2006.

3.3 The Luna Generating Station shall be included in TEP's original cost rate base at net book value as of December 31, 2006.

3.4 The average base cost of fuel and purchased power reflected in base rates shall be set at $0.028896/kWh, as calculated in Exhibit 4.

IV. COST OF CAPITAL.

4.1 The Signatories agree that a capital structure comprised of 57.50% debt and 42.50% common equity shall be adopted for ratemaking purposes in these consolidated dockets.

4.2 The Signatories agree that a return on common equity of 10.25% and an embedded cost of debt of 6.38% are appropriate and shall be adopted for ratemaking purposes in these consolidated dockets.

4.3 The Signatories agree to a fair value rate of return of 5.64%, as shown on Exhibit 1.

V. DEPRECIATION AND COST OF REMOVAL.

5.1 For ratemaking purposes, upon the effective date of a Commission order approving this Agreement, TEP shall use the depreciation rates for Distribution and General plant contained in the attached Exhibit 5 and incorporated herein.

5.2 For local and non-local generation plant, upon the effective date of the new base rates authorized in the Commission's order approving this Agreement, TEP shall use the depreciation rates attached hereto as Exhibit 5. These generation depreciation rates include an annual accrual of $21,626,296 on an ACC jurisdictional basis as negative net salvage (cost of removal) for "Generation," excluding the Luna Generating Station. The Luna Generating Station has separately identified depreciation rates included in Exhibit 5.

VI. IMPLEMENTATION COST RECOVERY ASSET.

6.1 TEP's original cost rate base shall include an Implementation Cost Recovery Asset ("ICRA") in the amount of $14,212,843 to reflect the following costs of TEP's transition to retail electric competition under the 1999 Settlement Agreement:

Account	Sub	Component	ICRA per Settlement	
18190	1508	Deferred Direct Access Costs	$	11,153,016
18190	1509	Deferred Divesiture Costs	$	1,193,003
18190	1510	Deferred GenCo Separation Costs	$	164,026
		Deferred Desert Star and West Connect Funding	$	1,702,798
		Total	$	14,212,843

6.2 For ratemaking purposes, the ICRA will be amortized by TEP over a four-year period commencing with the effective date of new rates from this proceeding and shall not be included in rate base or as an amortization expense in TEP's next rate case, pursuant to the Rate Moratorium provision of Paragraphs 10.1 and 10.2 herein.

VII. PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE.

7.1 The Signatories agree that it is in the public interest for TEP to recover its purchased power and fuel expenses through the use of a Purchased Power and Fuel Adjustment Clause ("PPFAC").

7.2 TEP shall be authorized to recover its purchased power and fuel expenses through the PPFAC as described herein. The following is a description of the major features of the PPFAC, details of which are included in the PPFAC Plan of Administration ("POA"), attached hereto as Exhibit 6 and incorporated herein:

a. The allowable PPFAC costs include fuel and purchased power costs incurred to provide service to retail customers. Additionally, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PPFAC. The allowable cost components include the following Federal Energy Regulatory Commission ("FERC") accounts: 501 Fuel (Steam), 547 Fuel (Other production), 555 Purchased Power, and 565 Wheeling (Transmission of Electricity by Others). These accounts are subject to change if FERC alters its accounting requirements or definitions.

b. The PPFAC shall allow for recovery of demand charges and costs of contracts used for hedging fuel and purchased power costs.

c. The average retail Base Cost of Fuel and Purchased Power embedded in base rates is set at $0.028896 per kWh.

d. The PPFAC rate will consist of two components, the Forward Component and the True-up Component.

e. The PPFAC Mechanism will be effective starting January 1, 2009. The PPFAC rate will be initially set at zero from January 1, 2009, through March 31, 2009. The first PPFAC Year (and applicable rate) will be from April 1, 2009, through March 31, 2010. The first True-up Component will include the period of January 1, 2009, through March 31, 2009.

f. The Forward Component will be updated on April 1st of each year, beginning April 1, 2009, and will be the forecasted fuel and purchased costs for the year commencing on April 1st and ending on March 31st of each individual PPFAC Year less the average Base Cost of Fuel and Purchased Power reflected in base rates ($0.028896 per kWh).

g. The True-up Component will reconcile any over-recovered or under-recovered amounts from the preceding PPFAC Year which will be credited to or recovered from customers in the next PPFAC Year.

h. TEP will file the PPFAC Rate with all component calculations for the PPFAC Year (that begins on the following April 1st), including all supporting data, with the Commission on or before October 31st of each year. TEP will update the October 31st filing by February 1st of the next year.

i. TEP has the ability to request an adjustment to the Forward Component at any time during a PPFAC Year should an extraordinary event occur that causes a drastic change in forecasted fuel and purchased power prices.

j. All Short-Term Wholesale Sales Revenue will be credited to fuel and purchased power costs.

k. Ten percent (10%) of annual net positive wholesale trading profits will be credited to fuel and purchased power costs annually. Under no circumstances will any annual net loss on wholesale trading incurred by TEP be shared with or borne by ratepayers.

l. Fifty percent (50%) of the revenues from sales of sulfur dioxide (SO_2) emission allowances will be credited to fuel and purchased power costs.

m. The Company will file monthly reports to Staff's Compliance Section and to RUCO detailing all calculations related to the PPFAC in a form and substance suitable to Staff and as detailed in the POA.

n. The Commission or Staff may review the prudence of fuel and power purchases at any time.

o. The Commission or Staff may review any calculation associated with the PPFAC at any time.

p. No change to the PPFAC rate shall become effective without Commission approval.

q. The balancing account shall accrue interest based on the one-year Nominal Treasury Constant Maturities rate. This rate is contained in the Federal Reserve Statistical Release, H-15, or its successor publication. The interest rate is adjusted annually on the first business day of the calendar year.

VIII. RENEWABLE ENERGY ADJUSTOR.

8.1 The Signatories agree that the REST adjustor mechanism recommended by Staff in its Direct Rate Design Testimony shall be adopted.

8.2 The initial rates of the REST Adjustor Mechanism will be the same as the REST Tariff charges approved in Decision No. 70314.

8.3 Subsequent changes to the REST Adjustor rates will be set in connection with the annual Renewable Energy Implementation Plan submitted by TEP and approved by the Commission pursuant to the Renewable Energy Standard and Tariff rules.

IX. DEMAND-SIDE MANAGEMENT PROGRAMS AND ADJUSTOR.

9.1 The Signatories support the implementation of an appropriate Demand-Side Management ("DSM") Portfolio and related Adjustor for TEP and agree to use their best efforts to implement an appropriate DSM Portfolio and Adjustor as soon as possible.

9.2 The Signatories agree that the Commission should adopt a DSM Adjustor mechanism for TEP to allow TEP to recover the reasonable and prudent costs of Commission-approved DSM programs. The initial funding level of the adjustor shall be $6,384,625. An initial adjustor rate of $0.000639/kWh applied to all kWh sales is required to generate the initial funding level. The DSM adjustor shall become effective when rates from this case become effective.

9.3 TEP's DSM adjustor mechanism shall include a performance incentive as recommended by Staff in its Direct Rate Design Testimony.

9.4 TEP shall apply interest whenever an over-collected balance results in a refund to customers. The interest rate shall be based on the one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15 or its successor publication. The interest rate should be adjusted annually on the first business day of the calendar year.

9.5 TEP shall file an application by April 1st of each year for Commission approval to reset the DSM Adjustor rates, and rates would be reset on June 1st of each year. The total amount to be recovered by the DSM Adjustor mechanism shall be calculated by projecting DSM costs for the next year, adjusted by the previous year's over- or under-collection, and adding revenue to be recovered from the DSM performance incentive. The total amount to be recovered would be divided by the appropriate projected retail sales (kWh) for the next year to calculate the per/kWh rate.

9.6 TEP shall file semi-annual DSM reports in Docket No. E-01933A-07-0401 (TEP's DSM Portfolio docket) by March 1st (for period ending December 31st) and September 1st (for period ending June 30th) of each year. The reports should contain the information set forth in Staff's DSM Testimony.

9.7 TEP may continue to propose new DSM programs for Commission review and approval. TEP may recover the reasonable and prudent costs of such Commission-approved programs through its DSM adjustor.

X. RATE CASE MORATORIUM.

10.1 Except as otherwise expressly provided herein, TEP's base rates, as authorized in the Commission order approving this Agreement, shall remain frozen through December 31, 2012, and no Signatory will seek any change to TEP's base rates that would take effect before January 1, 2013.

10.2 TEP shall not submit a rate application sooner than June 30, 2012. On or after June 30, 2012, TEP may not submit a rate application that uses a test year ending earlier than December 31, 2011. The Signatories agree to use their best efforts to have post-moratorium rates in place no later than thirteen months after TEP's rate application is filed with the Commission. For purposes of this paragraph, Staff will be deemed to have used its "best efforts" if it endeavors to process TEP's rate application within the timeframes set forth in A.A.C. R14-2-103. The Signatories recognize that Staff cannot ensure that the Commission will act on a rate application by any date certain.

10.3 The rate moratorium contained herein shall not preclude TEP from requesting, or the Commission from approving, changes to specific rate schedules or terms and conditions of service, or the approval of new rates or terms and conditions of service, that would have a de minimus impact upon TEP's Arizona jurisdictional earnings. For purposes of this Agreement, "de minimus impact" is defined as the lessor of (i) 0.04 percent (0.0004) of the agreed-upon Arizona jurisdictional fair value rate base of $1,451,558,000, as set forth in Exhibit 1, or (ii) a $600,000 annual impact on TEP's calendar year recorded net operating income during the years of the rate moratorium period. Nothing contained in this Agreement is intended to preclude the Commission from approving changes to TEP's tariffs or terms and conditions of service which are consistent with this Agreement.

XI. EMERGENCY CLAUSE.

11.1 Notwithstanding anything contained herein to the contrary, TEP shall not be prevented from requesting a change to its base rates, or necessary changes to the PPFAC mechanism, the DSM adjustor mechanism, or the REST adjustor mechanism, as may be applicable, that would take effect prior to January 1, 2013, in the event of conditions or circumstances that constitute an emergency. For the purposes of this Agreement, the term "emergency" is limited to an extraordinary event that is beyond TEP's control and that, in the Commission's judgment, requires rate relief in order to protect the public interest. This provision is not intended to preclude TEP from seeking rate relief pursuant to this paragraph in the event of the imposition of a federal carbon tax or related federal "cap and trade" system. This provision is not intended to preclude any party from opposing an application for rate relief filed by TEP pursuant to this paragraph.

XII. CERTIFICATE OF CONVENIENCE & NECESSITY.

12.1 The Signatories agree that a generic docket is an appropriate means by which the Commission could address the issue of exclusivity of the Certificates of Convenience and Necessity ("CC&N") of the "Affected Utilities" as defined in A.A.C. R14-2-1601.1, should the Commission choose to do so.

12.2 The Signatories acknowledge that TEP has the obligation to plan for and to serve all customers in its certificated service area, irrespective of size, and to recognize, in its planning, the existence of any Commission direct access program and the potential for future direct access customers. This Agreement does not bar any Party from seeking to amend TEP's obligation to serve or the Commission's prospective ratemaking treatment of TEP.

12.3 This Agreement is not intended to create, confirm, diminish, or expand an exclusive right for TEP to provide electric service within its certificated area where others may legally also provide such service, to diminish or expand any of TEP's rights to serve customers within its certificated area, or to prevent the Commission or any other governmental entity from amending the laws and regulations relative to public service corporations.

XIII. RETURNING CUSTOMER DIRECT ACCESS CHARGE.

13.1 TEP will file, as a compliance item, a Returning Customer Direct Access Charge ("RCDAC") tariff within ninety (90) days of the effective date of the Commission's order approving this Agreement. The RCDAC tariff will contain the following features:

a. The RCDAC shall apply only to individual customers or aggregated groups of customers with demand load of 3 MWs or greater.

b. The RCDAC shall not apply to a customer who provides TEP with one year's advance written notice of intent to return to TEP generation service and to take TEP Standard Offer service.

c. The RCDAC rate schedule shall identify the individual components of the potential charge, definitions of the components, and a general framework that describes the way in which the RCDAC would be calculated.

d. The RCDAC shall only be established to recover from Direct Access customers the additional costs, both one-time and recurring, that these customers would otherwise impose on other Standard Offer customers if and when the former return to Standard Offer service from their competitive suppliers. The customers shall pay the RCDAC in full within one year of the RCDAC being assessed.

13.2 The Signatories agree that a RCDAC as described above is in the public interest and should be adopted.

XIV. 1999 SETTLEMENT AGREEMENT.

14.1 The Signatories recognize that Decision No. 62103 and the 1999 Settlement Agreement were designed to allow a transition to retail electric competition within a specific time period. Inasmuch as the transition to retail electric competition has thus far not occurred and the time periods applicable to Decision No. 62103 and to the 1999 Settlement Agreement have passed, the Signatories recognize that it is necessary to address the prospective regulatory treatment that is appropriate for TEP under these circumstances.

14.2 To the extent that any party to the 1999 Settlement Agreement or any other party contends that the provisions of this Agreement are inconsistent with Decision No. 62103, the Signatories request that the Commission amend Decision No. 62103 to be consistent with this Agreement.

14.3 Under the circumstances in which TEP currently operates, it is appropriate to determine TEP's rates pursuant to cost-of-service ratemaking principles.

14.4 Upon the Commission's issuance of a final, non-appealable order approving this Agreement, TEP shall forego all claims relating to any alleged breach of contract resulting from or related to the 1999 Settlement Agreement and/or Decision No. 62103.

14.5 Upon the Commission's issuance of a final, non-appealable order approving this Agreement, TEP shall not seek to recover, in this or any subsequent proceeding, any amount that it claims is attributable to its alleged damages allegedly related to setting its rates under cost-of-service ratemaking principles.

14.6 Upon the Commission's issuance of a final, non-appealable order approving this Agreement, TEP shall not seek to recover, in this or any subsequent proceeding, any amount that it claims is attributable to any alleged damages allegedly related to the rate freeze adopted by the Commission in Decision No. 62103.

14.7 Upon the Commission's issuance of a final, non-appealable order approving this Agreement, TEP shall forego any and all claims related in any way to Decision No. 62103 or the 1999 Settlement Agreement.

14.8 Upon the Commission's issuance of a final, non-appealable order approving this Agreement, each Signatory hereby releases and forever discharges each other Signatory and the Commission from any and all claims, actions, and demands, of any nature whatsoever, past or present, whether arising out of any Commission order, statute, regulation, breach of contract, or any other theory, whether legal or equitable, including any claims, losses, costs or damages, in each case whether known or unknown, which such other Signatory or the Commission ever had, now have, or may in the future claim to have, arising from or pertaining to the 1999 Settlement Agreement and Decision No. 62103.

14.9 The Signatories recognize that certain waivers were provided to TEP under the 1999 Settlement Agreement. As these waivers were previously evaluated in the context of the then-contemplated transition to competition, they may not continue to be in the public interest. The Signatories agree that TEP shall file an application with the Commission addressing all of these waivers within ninety (90) days of the issuance of a Commission order approving this Agreement. In that proceeding, the Commission shall evaluate whether these waivers remain appropriate.

XV. FIXED CTC TRUE-UP REVENUES.

15.1 Certain issues related to the Fixed CTC True-up revenues remain unresolved by this Agreement, and the Signatories agree to present their respective positions in the hearing scheduled in this proceeding. Specifically, the Signatories shall present to the Commission their respective positions as to when TEP's new rates may go into effect and how TEP's Fixed CTC True-up revenues, as defined in Decision No. 69568, should be calculated and treated. The Signatories may present evidence to the Commission in the hearings scheduled in these consolidated dockets regarding these issues. This provision is not intended to limit any party's ability to present its position on these issues.

15.2 To the extent that the Commission determines that any Fixed CTC True-up revenues are to be credited to customers, then TEP agrees that an amount equal to any such Fixed CTC True-up revenues, up to $32.5 million, shall be credited to customers in the PPFAC balancing account.

15.3 The Commission shall determine the disposition of additional Fixed CTC True-up revenues, if any, to be credited to customers.

XVI. RATE DESIGN.

A. Rate Spread.

16.1 Except as set forth in Paragraph 16.28, the base revenue increase is to be spread across all customers such that each rate schedule shall reflect the same increase of 6.1% in adjusted base revenues as shown on Exhibit 7. The 6.1% increase is the result of holding low-income customers harmless from the rate increase. Selected rate schedules are attached as Exhibit 8.

16.2 This increase also applies to TEP's existing time-of-use schedules, which will be frozen to new subscription.

B. Inclining Block Rate Structure.

16.3 The Signatories agree that rate design can be used as an important energy conservation incentive. To accomplish this goal for the Residential Rate 01 service classification, the rate structure shall be redesigned as an inclining block rate, meaning that the unit price of electricity, excluding the customer charge, shall increase as consumption increases.

16.4 Residential Rate 01 shall have three blocks and shall be seasonally (summer/winter) differentiated with the first block applicable to kWh usage from 0 to 500 kWhs. The second block will be for usage of the next 3,000 kWhs or 501 kWhs to 3,500 kWhs. The third block will be for usage above 3,500 kWhs.

16.5 This rate structure recognizes that there are a large percentage of users that have relatively small usage, while also recognizing that a relatively small amount of users use a relatively large amount of energy. For example, during the Summer Period for Residential Rate 01, 27% of all bills are for usage under 500 kWhs per month. For those customers, the average usage is only 280 kWhs per month. In contrast, only 1.4% of all Residential Rate 01 bills contain usage above 3,500 kWhs. For these customers, the average usage is 4,766 kWhs per month.

16.6 General Service Rate 10 shall be redesigned to have an inclining block structure with two rates. The first rate shall apply to the first 500 kWhs per month, and the second rate for usage above 500 kWhs. Similar to Residential Rate 01, many General Service Rate customers are small users with 30% of the usage in this rate class falling under 500 kWhs. For these customers, average usage is approximately 200 kWhs.

C. Time-of-Use.

16.7 The Signatories agree that sending price signals to customers as to how TEP's cost to serve may change in different times of the year and times of the day provides an important energy conservation incentive. The Signatories therefore agree that expanding the availability of time-of-use rate schedules is in the public interest. All time-of-use rate schedules shall be available on an optional basis. Time-of-use will not be mandatory for any customer.

16.8 TEP will implement new time-of-use schedules that will be open for new subscription. Under newly implemented time-of-use rates, all residential, general service, large general service, and large light and power customers will be offered a time-of-use option.

16.9 TEP commits to design a program to educate customers on the potential for load shifting and bill reduction under time-of-use rates, and will make a good faith effort to promote time-of-use so as to increase subscription thereto.

16.10 TEP shall offer three new optional residential time-of-use schedules to replace the current (to-be-frozen) Rate 70. The customer charges under the three new rates will be $8.00 per month.

16.11 The three new residential options shall be offered to allow a customer to choose a schedule fitting his lifestyle and to result in load shifting that will be beneficial to system operations.

16.12 The three new residential time-of-use schedules shall offer customers flexibility for weekend usage, which should make the new optional rates attractive to potential subscribers.

16.13 In order for customers to clearly see the advantages of shifting power to the off-peak period, there are several key elements of the residential time-of-use schedules as compared to the non-time-of-use schedules:

a) Each time-of-use option will have the same inclining block rate structure as the non-time-of-use schedule.

b) The rate for the shoulder period for the time-of-use schedules will be between the peak and off-peak rate.

c) The rate for the peak periods for the time-of-use schedules will be higher than the rate for the non-time-of-use schedule.

d) The rate for the off-peak periods for the time-of-use schedules will be lower than the rate for the non-time-of-use schedule.

16.14 Time-of-use rates shall be seasonally differentiated. "Summer" shall include the billing months of May through October. "Winter" shall include the billing months of November through April.

16.15 New time-of-use schedules shall include:
Rate 70N-B Residential Time-of-Use – (Weekend Shoulder)
Rate 70N-C Residential Time-of-Use – (Weekend Super-Peak)

Rate 70N-D Residential Time-of-Use – (Weekend Off-Peak)
Rate 201BN Special Residential Time-of-Use (Guarantee Home)
Rate 201CN Special Residential Time-of-Use/Solar (Guarantee Home)
Rate 76N General Service Time-of-Use
Rate 85N Large General Service Time-of-Use
Rate 90N Large Light and Power Time-of-Use

16.16 Under Rate 70N-B (Weekend Shoulder), on summer weekends and selected holidays, the shoulder period will be 2 p.m. - 8 p.m. with no peak period. On winter weekends and selected holidays, there will be only an evening peak from 5 p.m. - 9 p.m. The winter morning peak period (6 a.m. - 10 a.m.), which applies on weekdays, will be treated as off-peak. Weekday hours under Rate 70N-B will be as follows: Summer Peak, 2 p.m. - 6 p.m.; Summer Shoulder, 12:00 noon - 2 p.m. and 6 p.m. - 8 p.m.; and Winter Peak, 6 a.m. – - 10 a.m. and 5 p.m. - 9 p.m.

16.17 Under Rate 70N-C (Weekend Super-Peak), there will be no weekend and holiday shoulder. On summer weekends and selected holidays, there will be a four-hour peak period from 2 p.m. - 6 p.m. All other weekend/holiday hours will be off-peak. On winter weekends and selected holidays, there will be a four-hour peak period from 5 p.m. - 9 p.m. The winter morning peak period (6 a.m. - 10 a.m.), which applies on the weekdays, is treated as off-peak. Weekday hours under Rate 70N-C match 70N-B. The hours differ only on weekends.

16.18 Under Rate 70N-D (Weekends Off-Peak), all weekend and selected holiday hours will be off-peak. Weekday hours under Rate 70N-C match 70N-B. The hours differ only on weekends.

16.19 The new non-residential time-of-use rates shall apply to each day of the year, with no distinction for weekdays, weekend days, or holidays. Peak demand charges, where they exist, will apply to periods designated as shoulder, in addition to peak periods.

16.20 The non-residential time-of-use schedules will have a summer on-peak period from 2 p.m. - 6 p.m., and two shoulder periods from 12 noon - 2 p.m. and 6 p.m. - 8 p.m. Other summer hours will be off-peak. The winter peak period shall run from 6 a.m. - 10 a.m. and 5 p.m. - 9 p.m. Other winter hours shall be off-peak.

16.21 Current residential time-of-use rate schedules shall be frozen to new subscription. Frozen rate schedules shall remain in place for existing customers at existing sites or delivery points. New customers will not be eligible for service under frozen schedules.

16.22 Frozen time-of-use schedules shall include:

Rate 21 Residential Time-of-Use
Rate 70 Residential Time-of-Use (with shoulder)
Rate 201B Special Residential Time-of-Use (Guarantee Home)
Rate 201C Special Residential Time-of-Use/Solar (Guarantee Home)
Rate 76 General Service Time-of-Use
Rate 85A Large General Service Time-of-Use
Rate 85F Large General Service Time-of-Use
Rate 90A Large Light and Power Time-of-Use
Rate 90F Large Light and Power Time-of-Use

16.23 TEP agrees to publicize in a manner agreeable to Staff the current Residential TOU Rate 70 so as to give customers a final opportunity to subscribe before the schedule is closed to all new subscription.

 DECISION NO. ______

D. Other Rate Design Changes.

16.24 The customer charge in Residential Rate 01 shall be $7.00 per month.

16.25 Time-of-Use Rates Large General Service Rate 85N and Large Light and Power Rate 90N shall be seasonally differentiated and have substantial non-fuel cost recovery through demand charges, which will help TEP to control peak demand.

16.26 Unbundled rates shall be designed such that the generation component is near cost (so as to facilitate economically efficient direct access), and the transmission component is tied to the FERC Open Access Transmission Tariff ("OATT").

16.27 Off-peak demand charges under Large General Service TOU Rate 85N, to be implemented under this Agreement, will apply to all off-peak kWs, rather than only off-peak kWs in excess of some threshold percent (e.g., 150%) of on-peak kWs (as in the case of Off-Peak *Excess* Demand Charges found in some of TEP's current Large General Service and Large Light and Power schedules). In contrast, Large Light and Power TOU Rate 90N, to be implemented under this Agreement, will continue the use of Excess Demand Charges.

E. Low-Income Tariffs.

16.28 The approximate 6% increase in base revenue will not apply to the existing low-income programs. As a result, all rate schedules except for the low-income schedules will receive a 6.1% increase. This holds current low-income customers harmless from the rate increase.

16.29 The following low-income tariffs will be frozen:
R-0401F - FROZEN, R-0421F - FROZEN, R-0470F - FROZEN, R-0501F - FROZEN, R-0521F - FROZEN, R-0570F - FROZEN, R-

05201AF - FROZEN, R-05201BF - FROZEN, and R-0621F - FROZEN, R-0821F – FROZEN. In the naming convention, the first two numbers correspond to the current low-income rider. The last numbers correspond to the existing rate to which the discount is applied. Therefore, R-0401F indicates existing low-income Rider 4 combined with existing Residential Rate 1.

16.30 The following low-income tariffs will remain open to new subscription: R-0601, R-0670, R-06201A, R-06201B, R-0801, R-0870, R-08201A, and R-08201B, R-08201C, and R-06201C.

16.31 Low income customers, both under frozen low-income tariffs and unfrozen low-income tariffs, will not be subject to the PPFAC. Incremental fuel and purchased power costs that these low-income customers would have otherwise paid under the PPFAC will be recovered from all remaining customers subject to the PPFAC.

XVII. RULES AND REGULATIONS.

17.1 TEP shall file its Rules and Regulations, including the changes proposed by TEP in its rate application and the changes thereto proposed by Staff, no later than June 11, 2008. It is the Signatories' understanding that the changes to TEP's Rules and Regulations shall not be inconsistent with the provisions of this Agreement.

17.2 Any Signatory to this Agreement shall raise in the hearing any contentions as to whether the Rules and Regulations proposed pursuant to Paragraph 17.1 are inconsistent with the terms of this Agreement or are otherwise inappropriate.

17.3 Among the significant changes to TEP's rules and regulations is the elimination of free footage from TEP's line extension tariffs.

XVIII. ADDITIONAL TARIFF FILINGS.

18.1 TEP agrees to file within ninety (90) days of the effective date of the Commission's approval of this Agreement the following tariffs, to be developed in consultation with Staff and interested stakeholders, as compliance items for Commission approval:

a. New Partial Requirements Tariffs that both protect TEP's ability to recover fixed costs and facilitate the development of renewable energy projects and environmentally friendly self-generation. These tariffs will be designed so as to not inhibit the installation of large scale solar or other renewable projects. The new Partial Requirement Tariffs shall provide for supplemental, standby, and maintenance services. Supplemental service shall be based on the unbundled delivery price components applicable to full requirements customers. Maintenance service shall be provided at a rate that recognizes that usage may be scheduled at times with lower cost-to-serve. Standby service shall be priced at such a level that balances the cost recovery needs of TEP with the desires of stakeholders to promote economically viable self-generation.

b. An Interruptible Tariff that provides a range of options with respect to notice requirements, duration, and frequency, and that will provide credits to participating customers based on avoided capacity costs. The interruptible program could also have options for "economic interruptions" as well as interruptions based on capacity or transmission constraints.

c. A Demand Response Program Tariff that establishes a voluntary program whereby customers reduce demand levels for specified durations upon notification by TEP that a critical situation exists. TEP will focus on enrolling interested commercial and industrial customers whose operations permit them to commit to specific load reduction targets during critical periods. The program will be designed so as to balance TEP's need to reduce peak demand with the customers' desire to maintain viable operations. TEP and stakeholders will also explore the potential advantages of a program through which interested parties could receive bill credits for verifiable demand reduction over expanded hours with high incremental costs. The bill credit program would be in addition to, not in place of, a voluntary program with no payments. Finally, TEP will explore notification methods whereby smaller customers, such as residential customers and smaller general service customers, can contribute to critical period load reduction.

d. A Bill Estimation Tariff that reflects the terms and procedures contained in TEP's Rules and Regulations, and additionally addresses specific permutations of demand and energy estimation for situations with varying history (e.g., at least twelve (12) months, less than twelve (12) months, or no history), status of customer at premise (new customer or existing customer), and status of premise (at least twelve (12) months premise history, less than twelve (12) months of premise history, or new premise).

XIX. FUEL AUDIT.

19.1 TEP agrees to implement the fuel audit recommendations set forth by Staff in its Direct Testimony, except that the fuel audit recommendations need not be completed prior to the implementation of the PPFAC. TEP should file an implementation plan within ninety (90) days of the effective date of the Commission's order approving this Agreement.

XX. MISCELLANEOUS PROVISIONS.

20.1 The Signatories agree that all currently filed testimony and exhibits shall be offered into the Commission's record as evidence. The Signatories acknowledge that the filing of testimony was suspended before Staff and the Intervenors filed their surrebuttal testimony. But for the suspension of the filing, some of the Signatories would have opposed TEP's rebuttal testimony and filed motions to strike certain TEP testimony that they believe was inappropriate. In the event that hearings resume on the 2007 Rate Application and the Motion to Amend, the Signatories reserve the right to file surrebuttal testimony, to file any motions to strike, or to seek any other relief.

20.2 The Signatories recognize that Staff does not have the power to bind the Commission. For purposes of proposing a settlement agreement, Staff acts in the same manner as any party to a Commission proceeding.

20.3 This Agreement shall serve as a procedural device by which the Signatories will submit their proposed settlement of these consolidated dockets to the Commission. Except for Paragraphs 16.23, 20.1–20.9, 20.12–20.13, and 20.15, this Agreement will not have any binding force or effect until its provisions are adopted as an order of the Commission.

20.4 The Signatories recognize that the Commission will independently consider and evaluate the terms of this Agreement. If the Commission issues an order adopting all material terms of this Agreement, such action shall constitute Commission approval of the Agreement. Thereafter, the Signatories shall abide by the terms as approved by the Commission.

20.5 In the event that the Commission fails to issue a final Order before December 31, 2008, any Signatory to this Agreement may withdraw from the Agreement, and such Signatory or Signatories may pursue their respective remedies.

20.6 If the Commission fails to issue an order adopting all material terms of this Agreement, any or all Signatories may withdraw from this Agreement, and such Signatory or Signatories may pursue without prejudice their respective remedies. For the purposes of this Agreement, whether a term is material shall be left to the discretion of the Signatory choosing to withdraw from the Agreement.

20.7 If TEP elects to withdraw from this Agreement pursuant to paragraphs 20.5 or 20.6, the Agreement shall become null and void and of no further force or effect.

20.8 This Agreement represents the Signatories' mutual desire to compromise and settle disputed issues in a manner consistent with the public interest. The terms and provisions of this Agreement apply solely to and are binding only in the context of the purposes and results of this Agreement. Nothing in this Agreement shall be construed as an admission by any Signatory that any of the positions or actions they have taken in the Motion to Amend, the 2007 Rate Application, or otherwise with respect to the 1999 Settlement Agreement are unreasonable or unlawful. Execution of the Agreement by the Signatories is without prejudice to any position taken by any of the Signatories in the Motion to Amend, the 2007 Rate Application, or otherwise with respect to the 1999 Settlement Agreement.

20.9 No Signatory is bound by any position asserted in negotiations, except as expressly stated in this Agreement. Evidence of conduct or statements made in the course of negotiating this Agreement shall not be admissible before this Commission, any other regulatory agency, or any court. None of the positions taken herein by any Signatory or in the negotiations surrounding this Agreement may be referred to, cited, or relied upon, as precedent or otherwise, in any other proceeding before the Commission, any other regulatory agency, or before any court for any other purpose except in furtherance of the purposes of this Agreement.

20.10 To the extent any provision of this Agreement is inconsistent with any existing Commission order, rule, or regulation, this Agreement shall control.

20.11 Any future Commission order, rule, or regulation shall be construed and administered, to the extent possible, in a manner so as not to conflict with the specific provisions of this Agreement, as approved by the Commission. Nothing contained in this Agreement is intended to interfere with the Commission's authority to exercise any regulatory authority by the issuance of orders, rules, or regulations.

20.12 The Signatories shall make all reasonable and good faith efforts necessary to obtain a Commission order approving this Agreement. The Signatories shall not take, support, or propose any action which would be inconsistent with this Agreement. Nothing contained in this Agreement is intended to otherwise interfere with any Signatory's ability to advocate its own position pursuant to Paragraphs 20.1 and 20.5-20.9 of this Agreement.

20.13 The Signatories shall actively defend this Agreement before the Commission, any other regulatory agency, or court in the event of any challenge to its validity or implementation. The Signatories expressly recognize, however, that Staff shall not be obligated to file any document or take any position that is inconsistent with a Commission order in this matter.

20.14 The terms of this Agreement are not severable, and each of such terms is in consideration of all other terms of this Agreement.

20.15 This Agreement may be executed in any number of counterparts and by each Signatory on separate counterparts, each of which when so executed and delivered shall be deemed an original and all of which taken together shall constitute one and the same instrument. This Agreement also may be executed electronically or by facsimile.

AGREED to as of this __________ day of _______, 2008

ARIZONA CORPORATION COMMISSION UTILITIES DIVISION

By: ________________________
Ernest G. Johnson
Director, Utilities Division

TUCSON ELECTRIC POWER COMPANY

By: ______________________________

Title: ______________________________

Date: ______________________________

RESIDENTIAL UTILITY CONSUMER OFFICE

By: ______________________________

Title: ______________________________

Date: ______________________________

ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION

By: ______________________________

Title: ______________________________

Date: ______________________________

AGREED to as of this May day of 29th, 2008

ARIZONA CORPORATION COMMISSION UTILITIES DIVISION

By: ______________________
Ernest G. Johnson
Director, Utilities Division

TUCSON ELECTRIC POWER COMPANY

By: ______________________

James S. Pignatelli
Chairman, President and Chief Executive Officer

SOUTHWESTERN POWER GROUP, II, LLC

Daniel H. Betts
____

General Manager
____

Date: 5/28/08
____

INTERNATIONAL BROTHERHOOD OF ELECTRIC
WORKERS LOCAL 1116

By:

Nicholas J. Enoch, Esq.
Lubin & Enoch, P.C.
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Title: Attorney

Date: May 29, 2008

SEMPRA ENERGY SOLUTIONS LLC

By: William B. Goddard

William B. Goddard
Commodity Supply & Operations

Title: Vice President

Date: 5·28·08

ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION

By ______________ Stan Barnes

Its President

Dated May 29, 2008

PHELPS DODGE MINING COMPANY

By ______________________

Its Vice President

Dated May 29, 2008

**PRIVILEGED AND CONFIDENTIAL SETTLEMENT COMMUNICATION
SUBJECT TO FED. R. EVID. 408 AND STATE LAW EQUIVALENT
TEP 041508 DRAFT**

BOWIE POWER STATION, LLC

By David H. Metts

General Manager

5/28/08

PRIVILEGED AND CONFIDENTIAL SETTLEMENT COMMUNICATION
SUBJECT TO FED. R. EVID. 408 AND STATE LAW EQUIVALENT
TEP 0415408

THE KROGER CO.

K Boehm

By: Kurt J. Boehm, Esq.

Title: Attorney For The Kroger Co.

Date: May 29, 2008

DOCKET NO. E-01933A-07-0402 ET AL.

MESQUITE POWER, LLC

By: Lawrence V. Robertson, Jr.

Title: Attorney

Date: May 29, 2008

DECISION NO. ____________

UNITED STATES DEPARTMENT OF DEFENSE AND ALL OTHER FEDERAL EXECUTIVE AGENCIES

By ______________________

ARIZONA INVESTMENT COUNCIL

By: ______________________

Title: President

Date: May 29, 2008

ARIZONA COMMUNITY ACTION ASSOCIATION

By ______________________
Executive Director

Settlement Exhibit No. 1

Tucson Electric Power Company
Computation of Increase in Gross Revenue Requirements
Test Year Ended December 31, 2006
(Thousands of Dollars)

Line No.	Description	ACC Jurisdiction Original Cost	ACC Jurisdiction RCND	ACC Jurisdiction Fair Value	Line No.
1	Adjusted Rate Base	$1,020,207	$1,882,910	$1,451,558	1
2	Adjusted Operating Income	($516)	($516)	($516)	2
3	Current Rate of Return (2/1)	-0.05%	-0.03%	-0.04%	3
4	Required Operating Income	$81,879	$81,879	$81,879	4
5	Required Rate of Return (4/1)	8.03%	4.35%	5.64%	5
6	Operating Income Deficiency	$82,395	$82,395	$82,395	6
7	Gross Revenue Conversion Factor	1.6598	1.6598	1.6598	7
8	Increase in Gross Revenue Requirement	$136,758	$136,758	$136,758	8

DOCKET NO. E-01933A-07-0402 ET AL.

TUCSON ELECTRIC POWER COMPANY
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
TEST YEAR ENDED DECEMBER 31, 2006

	Original Cost - ACC Jurisdictional			
	As Filed	Direct		
	TEP	ACC	Settlement	
	7/2/07	2/29/08	5/29/08	Summary
RATE BASE				
Original Cost Rate Base - Unadjusted	$1,154,149,459	$1,154,149,459	$1,154,149,459	
Rate Base Adjustments				
Implementation Cost Regulatory Asset (Staff B-3)	47,454,880	14,212,499	14,212,499	For purpose of settlement and to be reflected in rates in this proceeding Staff's original adjustment was accepted.
Springerville Unit 1 - Leasehold Improvements	($54,784,951)	(54,784,951)	-	For purpose of settlement and to be reflected in rates in this proceeding Springerville Unit 1 Leasehold Improvements are being reflected in rates at cost.
Renewable Resources	($6,727,183)	(6,727,183)	($6,727,183)	For purpose of settlement and to be reflected in rates in this proceeding TEP's original position was accepted.
Luna Plant (Staff B-2)	($45,829,034)	-	-	For purpose of settlement and to be reflected in rates in this proceeding Luna is being reflected in rates at cost.
Accum Depr- Cost of Removal (FAS 143) (Staff B-5)	-	(99,814,938)	-	For purpose of settlement and to be reflected in rates in this proceeding TEP's original position was accepted.
Accum Depr-Unauthorized Depreciation Rate Changes (Staff B-6)	-	(41,567,880)	-	For purpose of settlement and to be reflected in rates in this proceeding TEP's original position was accepted.
Other Deferred Credits (B-8 & Partial Staff B-7)	-	(2,625,627)	(1,585,878)	For purpose of settlement and to be reflected in rates in this proceeding Staff's original position was accepted, net of related ADIT.
Customer Care & Billing System (Staff B-9)	-	(4,364,894)	-	For purpose of settlement and to be reflected in rates in this proceeding TEP's original position was accepted.
Delayed Unitization	-	-	8,043,062	For purpose of settlement the parties agree with the increase plant in service and accumulated depreciation for generation plant that was in service at 12/31/06 but not unitized or included in FERC 106 (Completed Construction Not Classified).
Delayed Unitization - ADIT	-	-	(114,016)	For purpose of settlement the parties agree with the adjustment to test year recorded deferred income taxes associated with the increase in plant in service for generation plant that was in service at 12/31/06 but not unitized or included in FERC 106 (Completed Construction Not Classified).
Accumulated Deferred Income Taxes	($87,859,168)	(58,548,738)	($119,216,320)	The parties agree to the balance of ADIT to be included in rate base as properly synchronized with all settlement adjustments.
Allowance for Cash Working Capital (Staff B-4/B-4.1)	($22,017,047)	(24,642,425)	($24,797,303)	The parties agree to the balance of cash working capital to be included in rate base as properly synchronized with all settlement adjustments.
Allowance for Working Capital (Staff B-4.2)	($1,652,795)	(3,757,710)	($3,757,710)	For purpose of settlement and to be reflected in rates in this proceeding Staff's original adjustment was accepted.
ACC Jurisdictional Allocation Computation Errors	-	(9,325,662)	-	For purpose of settlement and to be reflected in rates in this proceeding TEP's corrections to ACC jurisdictional allocations were accepted.
Total Adjustments to Rate Base	(171,415,299)	(291,947,508)	(133,942,849)	
Rate Base	982,734,160	862,201,951	1,020,206,611	
Requested Rate of Return	8.35%	7.93%	8.03%	For purpose of settlement and to be reflected in rates a pro-forma capital structure of 42.50% Equity @ 10.25% and 57.50% Debt @ 6.38% was used.
Required Operating Income	$82,069,007	$68,335,490	$81,879,208	

DECISION NO. ______

TUCSON ELECTRIC POWER COMPANY COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT TEST YEAR ENDED DECEMBER 31, 2006	Original Cost - ACC Jurisdictional			
	As Filed TEP 7/2/07	Direct ACC 2/29/08	Settlement 5/29/08	Summary
OPERATING INCOME				
Original Operating Income - Unadjusted	$22,494,183	$22,494,183	$22,494,183	
Operating Revenue Adjustments				
Stranded Costs & Fixed CTC	(89,640,816)	(89,640,816)	(89,640,816)	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
SlimFast Contract Termination Fee	(278,215)	(278,215)	(278,215)	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Customer Annualization	7,514,575	7,514,575	7,514,575	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Weather Normalization	4,572,055	4,572,055	4,572,055	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Short-Term Sales Exclusion (Staff C-10)	-	25,259,000	-	For Purpose of settlement the parties have agreed to prospectively reduce PPFAC eligible cost by 100% of actual wholesale short-term sales margins by crediting 100% of wholesale short-term sales revenues and expenses to the PPFAC account.
Wholesale Trading Activity (Staff C-11)	-	171,900	-	For purpose of settlement the parties have agreed to prospectively reduce PPFAC eligible cost by 10% of actual net positive wholesale trading activity margins. Under no circumstances will any losses on wholesale trading be borne by ratepayers.
Heavy Equipment - Operating Lease	197,342	197,342	197,342	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Springerville Unit 1	(566,941)	(566,941)	(566,941)	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Renewable Resources	(6,888,380)	(6,888,380)	(6,888,380)	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Service Fees & Late Fees	1,308,077	1,308,077	2,469,342	For purpose of settlement and to be reflected in rates in this proceeding TEP's revised adjustment was accepted.
Lime Usage Costs	(598,676)	(598,676)	(598,676)	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Tri-State Fuel Oil Sales	(7,262,954)	(7,262,954)	(7,262,954)	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Building Usage Allocations	150,685	150,685	150,685	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Springerville Unit 3	(3,084,442)	(3,084,442)	(3,084,442)	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Total Adjustments to Operating Revenues	(94,577,690)	(69,146,790)	(93,416,425)	

TUCSON ELECTRIC POWER COMPANY
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
TEST YEAR ENDED DECEMBER 31, 2006

	Original Cost - ACC Jurisdictional			
	As Filed TEP 7/2/07	Direct ACC 2/29/08	Settlement 5/29/08	Summary
Operating Expense Adjustments				
Implementation Cost Regulatory Asset (Staff C-20)	11,863,806	4,580,212	4,580,212	For purpose of settlement and to be reflected in rates in this proceeding Staff's original adjustment was accepted.
Stranded Costs & Fixed CTC	(49,408,684)	(49,408,684)	(49,408,684)	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Customer Annualization	3,614,781	3,614,781	3,614,781	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Weather Normalization	2,085,037	2,085,037	2,085,037	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Unit Availability Normalization	6,973,411	6,973,411	6,973,411	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Short-Term Sales Exclusion	(46,954,540)	(46,954,540)	(46,954,540)	See discussion under Revenue for Staff Adj C-10
Wholesale Trading Activity	(93,487,237)	(93,487,237)	(93,487,237)	See discussion under Revenue for Staff Adj C-11
Test Power Exclusion	(1,370,321)	(1,370,321)	(1,370,321)	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Sundt Coal Contract	6,613,366	6,613,366	6,613,366	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Navajo Coal Contract	2,489,864	2,489,864	2,489,864	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
San Juan Coal (Staff C-4)	8,852,453	-	-	For purpose of settlement and to be reflected in rates in this proceeding Staff's original adjustment was accepted.
PPFAC Adjustment (Staff C-19)	14,309,410	-	-	For purpose of settlement and to be reflected in rates in this proceeding Staff's original adjustment was accepted.
Gain on Sale of S02 Allowances (Staff C-12)	6,348,930	(1,904,632)	6,348,930	For purpose of settlement and to be reflected in rates in this proceeding the parties have agreed to prospectively reduce retail PPFAC eligible cost by 50% of actual SO2 allowance margins.
Generating Facilities - Operating Lease	(18,720,148)	(18,720,148)	(18,720,148)	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted. (Springerville Unit 1 adjusted separately)
Heavy Equipment - Operating Lease	383,794	383,794	383,794	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Railcar - Operating Lease	(832,554)	(832,554)	(832,554)	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Springerville Unit 1	29,264,811	(15,100,033)	29,057,254	For purpose of settlement and to be reflected in rates the parties agree to adjustments that reflect cost based recovery of Springerville Unit 1 non-fuel cost.
Springerville Unit 1 Leasehold Improvements - Depreciation & Property Taxes	-	-	7,370,342	For purpose of settlement and to be reflected in rates the parties agree to adjustments that reflect recovery of Springerville Unit 1 leasehold improvements.
Springerville Unit 1 Delayed Plant - Depreciation & Property Tax	-	-	248,856	For purpose of settlement and to be reflected in rates in this proceeding TEP's adjustment was accepted.
Luna O&M (Staff C-2/C-3)	13,230,208	$2,121,530	2,121,530	For purpose of settlement and to be reflected in rates in this proceeding Staff's original adjustment was accepted.

TUCSON ELECTRIC POWER COMPANY
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
TEST YEAR ENDED DECEMBER 31, 2006

	Original Cost - ACC Jurisdictional			
	As Filed TEP 7/2/07	Direct ACC 2/29/08	Settlement 5/29/08	Summary
Plant Overhaul & Outage Normalization	1,161,990	1,161,990	1,161,990	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Renewable Resources	(4,320,436)	(4,320,436)	(4,320,436)	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Payroll Expense	1,348,225	1,348,225	2,737,397	For purpose of settlement and to be reflected in rates in this proceeding TEP's revised adjustment was accepted.
Payroll Tax Expense	125,796	125,796	227,154	For purpose of settlement and to be reflected in rates in this proceeding TEP's revised adjustment was accepted.
Pension & Benefits	(871,913)	(871,913)	(871,913)	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Post Retirement Medical	(58,438)	(58,438)	(58,438)	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Incentive Compensation (Staff C-7)	(941,683)	(4,515,289)	(4,515,289)	For purpose of settlement and to be reflected in rates in this proceeding Staff's original adjustment was accepted.
Rate Case Expense	201,003	201,003	201,003	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Membership Dues (Staff C-6)	(61,078)	(229,451)	(229,451)	For purpose of settlement and to be reflected in rates in this proceeding Staff's original adjustment was accepted.
Advertising & Sponsorship	(407,227)	(407,227)	(407,227)	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Outside Services	(342,795)	(342,795)	(342,795)	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
CC&B Normalization (Staff C-16)	433,987	(372,694)	433,987	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Out of Period Expenses	99,339	99,339	99,339	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Lime Usage Costs	(869,018)	(869,018)	(869,018)	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Tri-State Fuel Oil Sales	(6,796,486)	(6,796,486)	(6,796,486)	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Bad Debt Expense (Staff C-5)	622,366	(115,164)	(115,164)	For purpose of settlement and to be reflected in rates in this proceeding Staff's original adjustment was accepted.
Capital Cost Allocations	1,454,963	1,454,963	1,454,963	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Corporate Cost Allocations	(96,538)	(96,538)	(96,538)	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
SERP (Staff C-8)	-	(828,957)	(828,957)	For purpose of settlement and to be reflected in rates in this proceeding Staff's original adjustment was accepted.
Worker's Compensation (Staff C-9)	-	(323,907)	(323,907)	For purpose of settlement and to be reflected in rates in this proceeding Staff's original adjustment was accepted.
Legal Expense - Motion to Amend (Staff C-21)	-	(430,116)	(430,116)	For purpose of settlement and to be reflected in rates in this proceeding Staff's original adjustment was accepted.
Legal Expense - California Proceedings (Staff C-22)	-	(60,717)	(60,717)	For purpose of settlement and to be reflected in rates in this proceeding Staff's original adjustment was accepted.

TUCSON ELECTRIC POWER COMPANY
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
TEST YEAR ENDED DECEMBER 31, 2006

	Original Cost - ACC Jurisdictional			
	As Filed	Direct		
	TEP	ACC	Settlement	
	7/2/07	2/29/08	5/29/08	Summary
Generation Depreciation Rates Adjustment (Staff C-15)	-	1,626,296	21,626,296	For purpose of settlement and to be reflected in rates the parties agree on an adjustment o generation depreciation rates for the inclusion of $21.6 million (ACC Jurisdictional) in additional depreciation expense annually to recover cost of removal prospectively.
Markup Above Cost - Affiliate Charges SES (Staff C-17)	-	($211,514)	(211,514)	For purpose of settlement and to be reflected in rates in this proceeding Staff's original adjustment was accepted.
Normalize Affiliate Charges to TEP (Staff C-18)	-	($197,667)	(197,667)	For purpose of settlement and to be reflected in rates in this proceeding Staff's original adjustment was accepted.
Postage Expense (Staff C-23)	-	$64,946	64,946	For purpose of settlement and to be reflected in rates in this proceeding Staff's original adjustment was accepted.
West Connect Charges in ICRA (Staff C-24)	-	($198,156)	(198,156)	For purpose of settlement and to be reflected in rates in this proceeding Staff's original adjustment was accepted.
OATT	84,094,549	$84,094,549	84,094,549	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Springerville Unit 2 Delayed Plant - Depreciation & Property Tax	-	-	248,856	For purpose of settlement and to be reflected in rates in this proceeding TEP's revised adjustment was accepted.
Depreciation & Amort Expense Annualization	(7,575,744)	($7,575,744)	(7,575,744)	For purpose of settlement and to be reflected in rates in this proceeding TEP's original adjustment was accepted.
Property Tax	(2,107,937)	($2,609,940)	(2,499,929)	For purpose of settlement and to be reflected in rates in this proceeding the parties agree to the calculation of property taxes synchronized with all settlement adjustments.
Income Taxes	(19,259,510)	$31,264,971	(12,921,074)	For purpose of settlement and to be reflected in rates in this proceeding the parties agree to the calculation of income taxes synchronized with all settlement adjustments.
ACC Jurisdictional Allocation Computation Errors	-	(205,847)	-	For purpose of settlement and to be reflected in rates in this proceeding TEP's corrections to ACC jurisdictional allocations were accepted.
Total Adjustments to Operating Expense	(58,910,195)	(109,112,088)	(70,406,159)	
Total Net Adjustments	(35,667,495)	39,965,298	(23,010,266)	
Adjusted Operating Income	(13,173,312)	62,459,481	(516,083)	
Operating Income Deficiency	95,242,319	5,876,009	82,395,291	
Gross Revenue Conversion Factor	1.6609	1.6598	1.6598	
Increase in Gross Revenue Requirement Before TCRAC	**158,185,903**	**9,753,000**	**136,758,018**	
TCRAC	**117,622,513**	-		For purpose of settlement and to be reflected in rates in this proceeding Staff's original adjustment was accepted.
Recommended Increase in Base Rate Retail Revenues	**$ 275,808,416**	**$ 9,753,000**	**$ 136,758,018**	
Test Year Adjusted Retail Revenues	691,451,429	691,451,429	691,451,429	
Total Retail Revenues "Proposed" Rates - before PPFAC, DSM & REST	$ 967,259,845	$ 701,204,429	$ 828,209,447	
Test Year Adjusted Sales	9,318,849,104	9,318,849,104	9,318,849,104	
Average Retail Rate in Cents/kWh	10.38	7.52	8.89	

TUCSON ELECTRIC POWER COMPANY
SUMMARY PROOF OF REVENUE
TEST YEAR ENDED DECEMBER 31, 2006
PER SETTLEMENT - 6% OVERALL INCREASE

SUMMARY PAGE

	Residential	Commercial	Industrial	Public Authority	Lighting	Mines	TOTAL
Customers	357,254	34,743	14	35	26	2	392,074
kWhs	3,864,352,371	3,314,379,658	948,945,003	225,259,044	41,015,127	924,897,900	9,318,849,103
Current Revenues	$347,836,625	$308,402,277	$58,805,533	$16,053,066	$4,450,206	$45,544,537	$781,092,244
Proposed Revenues	$368,376,793	$327,326,477	$62,414,179	$17,038,066	$4,723,465	$48,338,959	$828,217,938
Percent Increase	5.9%	6.1%	6.1%	6.1%	6.1%	6.1%	6.0%

Fuel & Purchased Power

CLASS	TOTAL SALES (kWh)	Revenue	Avg Rate per Class	As a Percent
Residential	3,864,352,371	116,817,321	0.030229	43%
Commercial	3,314,379,658	95,220,881	0.028730	35%
Industrial	948,945,003	26,200,236	0.027610	10%
Mining	924,897,900	23,741,602	0.025669	9%
Public Authority	225,259,044	6,237,791	0.027692	2%
Lighting	41,015,127	1,058,888	0.025817	0%
Total	9,318,849,103	269,276,718	0.028896	

TUCSON ELECTRIC POWER COMPANY
LIFE LINE BUNDLED PROOF OF REVENUE
TEST YEAR ENDED DECEMBER 31, 2006
PER SETTLEMENT - 6% OVERALL INCREASE

Line No.	Pricing Plan		Adjusted Booked Billing Determinants	Existing Rates	Total Adjusted Revenue Requirement	Proposed Rate	Proposed Revenue
	RESIDENTIAL - SENIOR LIFELINE FROZEN -R0401F						
1	Customers (Single-Phase)		34,147	$4.90		$4.90	$167,320
2	Summer						
3	1st 500 kWhs		7,822,797	$0.090921		$0.090921	711,257
4	3,000 kWhs		5,366,439	$0.090921		$0.090921	487,922
	Winter						
5	1st 500 kWhs		5,308,943	$0.078970		$0.078970	419,247
6	3,000 kWhs		3,483,881	$0.078970		$0.078970	275,122
7	TOTAL REVENUE				$2,060,872		2,060,868
8	TOTAL R-0104F	kWh	21,982,060				-$4
9		Cust	2,846				
10	DISCOUNT						-$478,817
	RESIDENTIAL - SENIOR LIFELINE FROZEN - R0421F						
11	Customer Charge		76	$6.86		$6.86	$521
12	Summer On Peak kWhs		14,396	$0.125413		$0.125413	$1,805
13	Summer Off Peak kWhs		21,368	$0.050165		$0.050165	$1,072
14	Winter On Peak kWhs		12,633	$0.099018		$0.099018	$1,251
15	Winter Off Peak kWhs		41,013	$0.050165		$0.050165	$2,057
16	TOTAL REVENUE				$6,707		6,707
17							$0
18	TOTAL R-0421F	kWh	89,410				
19		Cust	6				
20	DISCOUNT						-$1,558
	RESIDENTIAL - SENIOR LIFELINE FROZEN - R0470F						
21	Customers		122	$6.78		$6.78	$827
22	Summer On Peak kWhs		12,367	$0.184171		$0.184171	$2,278
23	Summer Off Peak kWhs		51,483	$0.058160		$0.058160	$2,994
24	Summer Shoulder Peak kWhs		4,884	$0.116318		$0.116318	$568
25	Winter On Peak kWhs		9,846	$0.126011		$0.126011	$1,241
26	Winter Off Peak kWhs		34,940	$0.043619		$0.043619	$1,524
27	TOTAL REVENUE				$9,432		$9,432
28							$0
29	TOTAL R-0470F	kWh	113,520				
30		Cust	10				
31	DISCOUNT						-$2,191
	RESIDENTIAL - LIFELINE FROZEN -R0501F						
32	Customers (Single-Phase)		68,457	$4.90		$4.90	$335,439
	Summer						
33	1st 500 kWhs		20,649,467	$0.090921		$0.090921	1,877,470
34	3,000 kWhs		14,165,535	$0.090921		$0.090921	1,287,945
35	Winter						
36	1st 500 kWhs		14,013,765	$0.078970		$0.078970	1,106,667

TUCSON ELECTRIC POWER COMPANY
LIFE LINE BUNDLED PROOF OF REVENUE
TEST YEAR ENDED DECEMBER 31, 2006
PER SETTLEMENT - 6% OVERALL INCREASE

Line No.	Pricing Plan		Adjusted Booked Billing Determinants	Existing Rates	Total Adjusted Revenue Requirement	Proposed Rate	Proposed Revenue
37	3,000 kWhs		9,196,236	$0.078970		$0.078970	726,227
38	TOTAL REVENUE				$5,333,758		5,333,748
							-$10
39	TOTAL R-0501F	kWh	58,025,003				
40		Cust	5,705				
41	DISCOUNT						-$509,790

TUCSON ELECTRIC POWER COMPANY
LIFE LINE BUNDLED PROOF OF REVENUE
TEST YEAR ENDED DECEMBER 31, 2006
PER SETTLEMENT - 6% OVERALL INCREASE

Line No.	Pricing Plan		Adjusted Booked Billing Determinants	Existing Rates	Total Adjusted Revenue Requirement	Proposed Rate	Proposed Revenue
	RESIDENTIAL - LIFELINE FROZEN -R0521F						
1	Customer Charge		209	$6.86		$6.86	$1,434
2	Summer On Peak kWhs		50,261	$0.125413		$0.125413	$6,303
3	Summer Off Peak kWhs		74,606	$0.050165		$0.050165	$3,743
4	Winter On Peak kWhs		20,718	$0.099018		$0.099018	$2,051
5	Winter Off Peak kWhs		67,265	$0.050165		$0.050165	$3,374
6	TOTAL REVENUE				$16,906		16,906
7							$0
8	TOTAL R-0521F	kWh	212,850				
8		Cust	17				
10	DISCOUNT						-$1,616
	RESIDENTIAL - LIFELINE FROZEN -R0570F						
11	Customers		593	$6.78		$6.78	$4,021
12	Summer On Peak kWhs		62,455	$0.184171		$0.184171	$11,502
13	Summer Off Peak kWhs		259,993	$0.058160		$0.058160	$15,121
14	Summer Shoulder Peak kWhs		24,664	$0.116318		$0.116318	$2,869
15	Winter On Peak kWhs		49,723	$0.126011		$0.126011	$6,266
16	Winter Off Peak kWhs		176,452	$0.043619		$0.043619	$7,697
17	TOTAL REVENUE				$47,475		$47,475
18							$0
19	TOTAL R-0570F	kWh	573,287				
20		Cust	49				
21	DISCOUNT						-$4,538
	RESIDENTIAL - LIFELINE FROZEN -R05201AF						
22	Customers (Single-Phase)		159	$4.90		$4.90	$779
23	Mid-Summer kWhs		71,979	$0.090920		$0.090920	6,544
24	Remaining Summer kWhs		54,657	$0.074191		$0.074191	4,055
25	Winter kWhs		92,033	$0.064440		$0.064440	5,931
26	TOTAL REVENUE				$17,309		$17,309
27							$0
28	TOTAL R-05201AF	kWh	218,670				
29		Cust	13				
30	DISCOUNT						-$1,654
	RESIDENTIAL - LIFELINE FROZEN -R05201BF						
31	Customers		26	$6.78		$6.78	$176
32	Mid-Summer On Peak kWhs		1,890	$0.184171		$0.184171	$348
33	Mid-Summer Off Peak kWhs		7,659	$0.058160		$0.058160	$445
34	Mid-Summer Shoulder Peak kWhs		777	$0.116318		$0.116318	$90
35	Remaining Summer On Peak kWhs		1,199	$0.146415		$0.146415	$176
36	Remaining Summer Off Peak kWhs		4,878	$0.046236		$0.046236	$226
37	Remaining Summer Shoulder Peak kWhs		456	$0.092473		$0.092473	$42

TUCSON ELECTRIC POWER COMPANY
LIFE LINE BUNDLED PROOF OF REVENUE
TEST YEAR ENDED DECEMBER 31, 2006
PER SETTLEMENT - 6% OVERALL INCREASE

Line No.	Pricing Plan		Adjusted Booked Billing Determinants	Existing Rates	Total Adjusted Revenue Requirement	Proposed Rate	Proposed Revenue
38	Winter On Peak kWhs		3,499	$0.100179		$0.100179	$351
39	Winter Off Peak kWhs		11,142	$0.034673		$0.034673	$386
40	TOTAL REVENUE				$2,240		$2,240
41							$0
42	TOTAL R-05201BF	kWh	31,500				
43		Cust	2				
44	DISCOUNT						-$214

TUCSON ELECTRIC POWER COMPANY
LIFE LINE BUNDLED PROOF OF REVENUE
TEST YEAR ENDED DECEMBER 31, 2006
PER SETTLEMENT - 6% OVERALL INCREASE

Line No.	Pricing Plan		Adjusted Booked Billing Determinants	Existing Rates	Total Adjusted Revenue Requirement	Proposed Rate	Proposed Revenue
	RESIDENTIAL - LIFELINE ($8 DISCOUNT -R0601F (FROZEN)						
1	Customers (Single-Phase)		92,342	$4.90		$4.90	$452,476
	Summer						
2	1st 500 kWhs		25,447,243	$0.090921		$0.090921	2,313,689
3	3,000 kWhs		17,456,808	$0.090921		$0.090921	1,587,190
	Winter						
4	1st 500 kWhs		17,269,776	$0.078970		$0.078970	1,363,794
5	3,000 kWhs		11,332,924	$0.078970		$0.078970	894,961
6	**TOTAL REVENUE**				$6,612,123		$6,612,110
7							-$13
8	**TOTAL R-0601F**	kWh	71,506,752				
9		Cust	7,695				
10	**DISCOUNT**						-$760,937
	RESIDENTIAL - LIFELINE ($8 DISCOUNT -R0621F)						
11	Customer Charge		277	$6.86		$6.86	$1,900
12	Summer On Peak kWhs		81,686	$0.125413		$0.125413	$10,244
13	Summer Off Peak kWhs		121,253	$0.050165		$0.050165	$6,083
14	Winter On Peak kWhs		33,672	$0.099018		$0.099018	$3,334
15	Winter Off Peak kWhs		109,322	$0.050165		$0.050165	$5,484
16	**TOTAL REVENUE**				$27,046		$27,046
17							$0
18	**TOTAL R-0621F**	kWh	345,933				
19		Cust	23				
20	**DISCOUNT**						-$3,112
	RESIDENTIAL - LIFELINE ($8 DISCOUNT - R0670F)						
21	Customers		666	$6.78		$6.78	$4,515
22	Summer On Peak kWhs		68,711	$0.184171		$0.184171	$12,655
23	Summer Off Peak kWhs		286,037	$0.058160		$0.058160	$16,636
24	Summer Shoulder Peak kWhs		27,135	$0.116318		$0.116318	$3,156
25	Winter On Peak kWhs		54,704	$0.126011		$0.126011	$6,893
26	Winter Off Peak kWhs		194,127	$0.043619		$0.043619	$8,468
27	**TOTAL REVENUE**				$52,323		$52,323
28							$0
29	**TOTAL R-0670F**	kWh	630,714				
30		Cust	56				
31	**DISCOUNT**						-$6,021
	RESIDENTIAL - LIFELINE ($8 DISCOUNT - R06201AF)						
32	Customers (Single-Phase)		513	$4.90		$4.90	$2,514
33	Mid-Summer kWhs		197,796	$0.090920		$0.090920	17,984
34	Remaining Summer kWhs		150,197	$0.074191		$0.074191	11,143
35	Winter kWhs		252,904	$0.064440		$0.064440	16,297
36	**TOTAL REVENUE**				$47,938		$47,938
37							$0

DECISION NO. ____________

TUCSON ELECTRIC POWER COMPANY
LIFE LINE BUNDLED PROOF OF REVENUE
TEST YEAR ENDED DECEMBER 31, 2006
PER SETTLEMENT - 6% OVERALL INCREASE

Line No.	Pricing Plan		Adjusted Booked Billing Determinants	Existing Rates	Total Adjusted Revenue Requirement	Proposed Rate	Proposed Revenue
38	TOTAL R-06201AF	kWh	600,897				
39		Cust	43				
40	DISCOUNT						-$5,517

TUCSON ELECTRIC POWER COMPANY
LIFE LINE BUNDLED PROOF OF REVENUE
TEST YEAR ENDED DECEMBER 31, 2006
PER SETTLEMENT - 6% OVERALL INCREASE

Line No.	Pricing Plan		Adjusted Booked Billing Determinants	Existing Rates	Total Adjusted Revenue Requirement	Proposed Rate	Proposed Revenue
	RESIDENTIAL - LIFELINE ($8 DISCOUNT - R06201BF)						
1	Customers		12	$6.78		$6.78	$81
2	Mid-Summer On Peak kWhs		992	$0.184171		$0.184171	$183
3	Mid-Summer Off Peak kWhs		4,019	$0.058160		$0.058160	$234
4	Mid-Summer Shoulder Peak kWhs		408	$0.116318		$0.116318	$47
5	Remaining Summer On Peak kWhs		629	$0.146415		$0.146415	$92
6	Remaining Summer Off Peak kWhs		2,560	$0.046236		$0.046236	$118
7	Remaining Summer Shoulder Peak kWhs		240	$0.092473		$0.092473	$22
8	Winter On Peak kWhs		1,836	$0.100179		$0.100179	$184
9	Winter Off Peak kWhs		5,847	$0.034673		$0.034673	$203
10	**TOTAL REVENUE**				$1,164		$1,164
11							$0
12	**TOTAL R-06201BF**	kWh	16,530				
13		Cust	1				
14	**DISCOUNT**						-$134
	RESIDENTIAL - LIFELINE MEDICAL LIFE SUPPORT -R0801F (FROZEN)						
15	Customers (Single-Phase)		8,506	$4.90		$4.90	$41,679
	Summer						
16	1st 500 kWhs		3,233,238	$0.090921		$0.090921	293,969
17	3,000 kWhs		2,218,001	$0.090921		$0.090921	201,663
	Winter						
18	1st 500 kWhs		2,194,237	$0.078970		$0.078970	173,279
19	3,000 kWhs		1,439,922	$0.078970		$0.078970	113,711
20	**TOTAL REVENUE**				$824,303		$824,301
21							-$2
22	**TOTAL R-0801F**	kWh	9,085,398				
23		Cust	709				
24	**DISCOUNT**						-$226,572
	RESIDENTIAL - LIFELINE MEDICAL LIFE SUPPORT -R0821F (FROZEN)						
25	Customer Charge		67	$6.86		$6.86	$460
26	Summer On Peak kWhs		16,761	$0.125413		$0.125413	$2,102
27	Summer Off Peak kWhs		24,879	$0.050165		$0.050165	$1,248
28	Winter On Peak kWhs		6,909	$0.099018		$0.099018	$684
29	Winter Off Peak kWhs		22,431	$0.050165		$0.050165	$1,125
30	**TOTAL REVENUE**				$5,619		$5,619
31							$0
32	**TOTAL R-0821F**	kWh	70,980				
33		Cust	6				
34	**DISCOUNT**						-$1,544
	RESIDENTIAL - LIFELINE MEDICAL LIFE SUPPORT -R0870F (FROZEN)						
35	Customers		141	$6.78		$6.78	$956

TUCSON ELECTRIC POWER COMPANY
LIFE LINE BUNDLED PROOF OF REVENUE
TEST YEAR ENDED DECEMBER 31, 2006
PER SETTLEMENT - 6% OVERALL INCREASE

Line No.	Pricing Plan		Adjusted Booked Billing Determinants	Existing Rates	Total Adjusted Revenue Requirement	Proposed Rate	Proposed Revenue
36	Summer On Peak kWhs		17,036	$0.184171		$0.184171	$3,138
37	Summer Off Peak kWhs		70,919	$0.058160		$0.058160	$4,125
38	Summer Shoulder Peak kWhs		6,728	$0.116318		$0.116318	$783
39	Winter On Peak kWhs		13,563	$0.126011		$0.126011	$1,709
40	Winter Off Peak kWhs		48,131	$0.043619		$0.043619	$2,099
41	**TOTAL REVENUE**				**$12,809**		**$12,809**
42							$0
43	**TOTAL R-0870F**	kWh	156,378				
44		Cust	12				
45	**DISCOUNT**						**-$3,521**

TUCSON ELECTRIC POWER COMPANY
LIFE LINE BUNDLED PROOF OF REVENUE
TEST YEAR ENDED DECEMBER 31, 2006
PER SETTLEMENT - 6% OVERALL INCREASE

Line No.	Pricing Plan		Adjusted Booked Billing Determinants	Existing Rates	Total Adjusted Revenue Requirement	Proposed Rate	Proposed Revenue
	RESIDENTIAL - LIFELINE MEDICAL LIFE SUPPORT -R08201AF (FROZEN)						
1	Customers (Single-Phase)		18	$4.90		$4.90	$88
2	Mid-Summer kWhs		4,677	$0.090920		$0.090920	425
3	Remaining Summer kWhs		3,552	$0.074191		$0.074191	264
4	Winter kWhs		5,981	$0.064440		$0.064440	385
5	TOTAL REVENUE				$1,162		$1,162
6							$0
7	TOTAL R-08201AF	kWh	14,210				
8		Cust	2				
9	DISCOUNT						-$320

Line No.	RESIDENTIAL - LIFELINE SUMMARY	CUSTOMERS	kWh		DISCOUNT	Revenue
1	LIFE LINE R01	203,452	160,599,213.00	$14,831,056	(1,976,117)	$12,854,940
2	LIFE LINE R21	629	719,173.00	$56,277	(7,831)	$48,446
3	LIFE LINE R70	1,522	1,473,899.00	$122,040	(16,271)	$105,768
4	LIFE LINE R201A	690	833,777.00	$66,409	(7,491)	$58,919
5	LIFE LINE R201B	38	48,030.00	$3,405	(348)	$3,057
6	Annual Totals	206,331	163,674,092	$15,079,187	(2,008,058)	$13,071,130
7	Average Monthly Lifeline Customers	17,194				
8	TOTAL ANNUAL DISCOUNT			(2,008,058)		2,008,058
9	TOTAL REVENUE INCLUDING DISCOUNT			$13,071,130		$15,079,187

TUCSON ELECTRIC POWER COMPANY
RESIDENTIAL BUNDLED PROOF OF REVENUE
TEST YEAR ENDED DECEMBER 31, 2006
PER SETTLEMENT - 6% OVERALL INCREASE

Line No.	Pricing Plan		Adjusted Booked Billing Determinants	Existing Rates	Total Adjusted Revenue Requirement	Proposed Rate	Proposed Revenue
	RESIDENTIAL- R01N						
1	Customers (Single-Phase)		3,899,485	$4.90		$7.00	$27,296,392
2	Customer (Three-Phase)		3,804	$12.26		$13.00	49,452
	Summer						
3	1st 500 kWhs		845,371,595	$0.090921		$0.046925	39,669,062
4	3,000 kWhs		1,263,575,096	$0.090921		$0.068960	87,136,139
5	3,501 kWhs and above		37,355,185	$0.090921		$0.088960	3,323,117
	Winter						
6	1st 500 kWhs		794,100,459	$0.078970		$0.047309	37,568,099
7	3,000 kWhs		533,236,566	$0.078970		$0.067309	35,891,620
8	3,501 kWhs and above		6,420,049	$0.078970		$0.087309	560,528
9	Revenue Delivery Charges				$231,494,079		$231,494,408
	Fuel & Purchased Power						
10	Summer		2,146,301,876		71,252,930	$0.033198	71,252,930
11	Winter		1,333,757,074		34,274,889	$0.025698	34,274,889
12	**TOTAL REVENUE**				$337,021,898		$337,022,227
							$329
13	**TOTAL R-01 -**	kWh	3,480,058,950				
14		Cust	325,274				
	RESIDENTIAL WATER HEATING - R-02 (FROZEN)						
15	Customers		28,728	$0.00		0	$0
16	First 100 kWh Charge		2,472,456	$7.85		$5.10	$146,513
17	Delivery, additional kWhs		2,788,089	$0.054358		$0.000000	0
18	Delivery, additional kWhs		5,260,545			0.01729800	$90,997
19	Revenue Delivery Charges				$237,546		$237,510
20	Fuel & Purchased Power		5,260,545		154,913	$0.029448	154,913
21	**TOTAL REVENUE**				$392,458	$0.029448	$392,422
							-$36
22	**TOTAL R-02**	kWh	5,260,545				
23		Cust					
	RESIDENTIAL TIME OF USE - R-21 (FROZEN)						
24	Customer Charge		33,883	$6.86		$7.00	$237,181
25	Summer On Peak kWhs		12,261,237	$0.125413		$0.101271	1,241,708
26	Summer Off Peak kWhs		18,200,250	$0.050165		$0.021508	391,451
27	Winter On Peak kWhs		5,047,599	$0.099018		$0.073292	369,949
28	Winter Off Peak kWhs		16,387,663	$0.050165		$0.021508	352,466
29	Revenue Delivery Charges				$2,592,736		$2,592,754
	Fuel & Purchased Power						
30	Summer On Peak		12,261,237		652,273	$0.053198	652,273
31	Summer Off Peak		18,200,250		422,209	$0.023198	422,209
32	Winter On Peak		5,047,599		205,427	$0.040698	205,427
33	Winter Off Peak		16,387,663		339,192	$0.020698	339,192
34	**TOTAL REVENUE**				$4,211,838		$4,211,856
							$18

TUCSON ELECTRIC POWER COMPANY
RESIDENTIAL BUNDLED PROOF OF REVENUE
TEST YEAR ENDED DECEMBER 31, 2006
PER SETTLEMENT - 6% OVERALL INCREASE

Line No.	Pricing Plan		Adjusted Booked Billing Determinants	Existing Rates	Total Adjusted Revenue Requirement	Proposed Rate	Proposed Revenue
35	TOTAL R-21	kWh	51,896,749				
36		Cust	2,824				

TUCSON ELECTRIC POWER COMPANY
RESIDENTIAL BUNDLED PROOF OF REVENUE
TEST YEAR ENDED DECEMBER 31, 2006
PER SETTLEMENT - 6% OVERALL INCREASE

Line No.	Pricing Plan		Adjusted Booked Billing Determinants	Existing Rates	Total Adjusted Revenue Requirement	Proposed Rate	Proposed Revenue
	RESIDENTIAL TIME OF USE - R70F (FROZEN)						
1	Customers		49,226	$6.78		$7.00	$344,582
2	Summer On Peak kWhs		6,828,127	$0.184171		$0.174747	1,193,195
3	Summer Off Peak kWhs		28,424,608	$0.058160		$0.041176	1,170,412
4	Summer Shoulder Peak kWhs		2,696,519	$0.116318		$0.102823	277,264
5	Winter On Peak kWhs		5,436,116	$0.126011		$0.025762	140,045
6	Winter Off Peak kWhs		19,291,152	$0.043619		$0.023098	445,587
7	Revenue Delivery Charges				$3,571,056		$3,571,085
	Fuel & Purchased Power						
8	Summer On Peak		6,828,127		380,313	$0.055698	380,313
9	Summer Off Peak		28,424,608		659,394	$0.023198	659,394
10	Summer Shoulder Peak		2,696,519		129,967	$0.048198	129,967
11	Winter On Peak		5,436,116		221,239	$0.040698	221,239
12	Winter Off Peak		19,291,152		399,288	$0.020698	399,288
13	**TOTAL REVENUE**				$5,361,257		$5,361,286
14							$29
15	**TOTAL R-70**	kWh	62,676,522				
16		Cust	4,102				
	SPECIAL RESIDETNIAL ELECTRIC SERVICE - R-201AF (FROZEN)						
17	Customers (Single-Phase)		85,448	$4.90		$7.00	$598,139
18	Mid-Summer kWhs		29,875,657	$0.090920		$0.066139	1,975,946
19	Remaining Summer kWhs		22,686,070	$0.074191		$0.044138	1,001,318
20	Winter kWhs		38,199,266	$0.064440		$0.033803	1,291,250
21	Revenue Delivery Charges				$4,866,641		$4,866,653
22	Fuel & Purchased Power						
23	Mid and Remaining Summer		52,561,727		1,744,944	$0.033198	1,744,944
24	Winter		38,199,266		981,645	$0.025698	981,645
25	**TOTAL REVENUE**				$7,593,230		$7,593,242
26							$12
27	**TOTAL R-201A**	kWh	90,760,993				
28		Cust	7,121				
	SPECIAL RESIDENTIAL ELECTRIC SERVICE TIME OF USE - R-201BF (FROZEN)						
29	Customers		6,315	$6.78		$7.00	$44,208
30	Mid-Summer On Peak kWhs		452,323	$0.184171		$0.166303	$75,223
31	Mid-Summer Off Peak kWhs		1,833,284	$0.058160		$0.031395	$57,556
32	Mid-Summer Shoulder Peak kWhs		186,047	$0.116318		$0.093043	$17,310
33	Remaining Summer On Peak kWhs		287,033	$0.146415		$0.124945	$35,863
34	Remaining Summer Off Peak kWhs		1,167,626	$0.046236		$0.018756	$21,900
35	Remaining Summer Shoulder Peak kWhs		109,262	$0.092473		$0.067767	$7,404
36	Winter On Peak kWhs		837,667	$0.100179		$0.075935	$63,608
37	Winter Off Peak kWhs		2,667,167	$0.034673		$0.006499	$17,334

TUCSON ELECTRIC POWER COMPANY
RESIDENTIAL BUNDLED PROOF OF REVENUE
TEST YEAR ENDED DECEMBER 31, 2006
PER SETTLEMENT - 6% OVERALL INCREASE

Line No.	Pricing Plan		Adjusted Booked Billing Determinants	Existing Rates	Total Adjusted Revenue Requirement	Proposed Rate	Proposed Revenue
38	Revenue Delivery Charges				$340,403		$340,407
	Fuel & Purchased Power						
39	Mid and Remaining On Peak		739,356		41,181	$0.055698	41,181
40	Mid and Remaining Off Peak		3,000,910		69,615	$0.023198	69,615
41	Mid and Remaining Summer Shoulder Peak		295,309		14,233	$0.048198	14,233
42	Winter On Peak		837,667		34,091	$0.040698	34,091
43	Winter Off Peak		2,667,167		55,205	$0.020698	55,205
44	TOTAL REVENUE				$554,729		$554,732
45							$3
46	TOTAL R-201B	kWh	7,540,408				
47		Cust	526				
	SPECIAL RESIDENTIAL ELECTRIC SERVICE TIME OF USE - R-201C (FROZEN)						
1	Customers		2,560	$6.78		$7.00	$17,921
2	Mid-Summer On Peak kWhs		134,707	$0.184171		$0.161981	$21,820
3	Mid-Summer Off Peak kWhs		594,771	$0.058160		$0.028409	$16,897
4	Mid-Summer Shoulder Peak kWhs		60,391	$0.116318		$0.090057	$5,439
5	Remaining Summer On Peak kWhs		95,071	$0.137207		$0.112200	$10,667
6	Remaining Summer Off Peak kWhs		446,067	$0.043328		$0.012688	$5,660
7	Remaining Summer Shoulder Peak kWhs		44,054	$0.086658		$0.058618	$2,582
8	Winter On Peak kWhs		266,218	$0.093879		$0.066272	$17,643
9	Winter Off Peak kWhs		842,833	$0.032491		$0.001201	$1,012
10	Revenue Delivery Charges				$99,638		$99,640
	Fuel & Purchased Power						
11	Mid-Summer On Peak		229,778		12,798	$0.055698	12,798
12	Mid-Summer Off Peak		1,040,837		24,145	$0.023198	24,145
13	Mid-Summer Shoulder Peak		104,445		5,034	$0.048198	5,034
14	Winter On Peak		266,218		10,835	$0.040698	10,835
15	Winter Off Peak		842,833		17,445	$0.020698	17,445
16	TOTAL REVENUE				$169,895		$169,897
17							$2
18	TOTAL R-201C	kWh	2,484,111				
19		Cust	213				
	RESIDENTIAL SUMMARY						
20	TOTAL RESIDENTIAL REVENUE				$368,376,435		$368,376,793
21	TOTAL RESIDENTIAL KWHS		3,864,352,371				
22	TOTAL RESIDENTIAL CUSTOMERS		357,254				$357

TUCSON ELECTRIC POWER COMPANY
GENERAL SERVICE BUNDLED PROOF OF REVENUE
TEST YEAR ENDED DECEMBER 31, 2006
PER SETTLEMENT - 6% OVERALL INCREASE

Line No.	Pricing Plan		Adjusted Booked Billing Determinants	Existing Rates	Total Adjusted Revenue Requirement	Proposed Rate	Proposed Revenue
	SMALL GENERAL SERVICE - GS-10						
1	Customers (Single-Phase)		200,229	$5.88		$8.00	$1,601,834
2	Customer (Three-Phase)		192,377	$13.24		$14.00	$2,693,280
3	Energy First 3400 kWh per month		287,747,871	$0.113695			
	Summer						
4	1st 500 kWhs		80,994,098	$0.100343		$0.056236	$4,554,784
5	all remaining kWhs		942,438,232	$0.100343		$0.085145	$80,243,903
	Winter						
7	1st 500 kWhs		78,781,616	$0.093772		$0.051252	$4,037,715
8	all remaining kWhs		661,228,028	$0.093772		$0.080145	$52,994,120
9	Revenue Delivery Charges				$146,125,228		$146,125,638
	Fuel & Purchased Power						
10	Summer		1,023,432,330		32,289,290	$0.031550	32,289,290
11	Winter		740,009,644		17,924,514	$0.024222	17,924,514
12	**TOTAL REVENUE**				$196,339,032		$196,339,441
13							$409
14	**TOTAL GS-10**	kWh	1,763,441,974				
15		Cust	32,717				
	SMALL GENERAL SERVICE - PRS-10 - CONTRACT						
16	Revenue Delivery Charges				$23,154		$23,154
17	Fuel & Purchased Power		211,780		6,084	0.028730	6,084
18							
19	**TOTAL REVENUE**				$29,239		$29,239
20							$0
21	**TOTAL PRS-10**	kWh	211,780				
22		Cust	1				
	GENERAL SERVICE MOBILE HOME PARKS GS-11 (FROZEN)						
23	Customers (Single-Phase)		3,948	$5.88		$8.00	$31,584
24	Customer (Three-Phase)		336	$13.24		$14.00	4,704
25	Energy Summer		33,529,195	$0.090921		$0.067290	2,256,180
26	Energy Winter		26,803,344	$0.079870		$0.052751	1,413,903
27	Revenue Delivery Charges				$3,705,988		$3,706,371
28							
29	Fuel & Purchased Power		60,332,539		1,733,354	$0.0287300	1,733,354
30	1st 100 kWhs		28,728		$5,439,342		$5,439,725
31							$383
32	**TOTAL GS-11**	kWh	60,332,539				
33		Cust	357				

TUCSON ELECTRIC POWER COMPANY
GENERAL SERVICE BUNDLED PROOF OF REVENUE
TEST YEAR ENDED DECEMBER 31, 2006
PER SETTLEMENT - 6% OVERALL INCREASE

Line No.	Pricing Plan		Adjusted Booked Billing Determinants	Existing Rates	Total Adjusted Revenue Requirement	Proposed Rate	Proposed Revenue
	GENERAL SERVICE TIME OF USE - GS-76 - (FROZEN)						
1	Customers (Single-Phase)		4,203	$6.78		$8.00	$33,627
2	Customer (Three-Phase)		7,473	$14.14		$14.00	104,617
3	Summer On-Peak		11,986,862	$0.222943		$0.207220	2,483,918
4	Summer Off-Peak		59,438,241	$0.067853		$0.042825	2,545,443
5	Summer Shoulder Peak		4,224,622	$0.140551		$0.119884	506,465
6	Winter On Peak		13,067,365	$0.150244		$0.130159	1,700,835
7	Winter Off Peak		48,010,642	$0.053312		$0.027411	1,316,020
9	Revenue Delivery Charges				$8,690,880		$8,690,923
	Fuel & Purchased Power		136,727,732				
10	Summer On-Peak		16,211,484		909,837	$0.056123	909,837
11	Summer Off-Peak		59,438,241		1,404,110	$0.023623	1,404,110
12	Winter On Peak		13,067,365		507,131	$0.038809	507,131
13	Winter Off Peak		48,010,642		903,032	$0.018809	903,032
14	**TOTAL REVENUE**				**$12,414,990**		**$12,415,034**
15							$43
16	**TOTAL GS-76**	kWh	136,727,732				
17		Cust	973				
	INTERRUPTIBLE AGRICULTURAL PUMPING GS-31						
18	Summer - all Kwhs		11,457,973	$0.051500		$0.025700	$294,470
19	Winter - all kWhs		4,738,919	$0.050208		$0.024205	$114,706
20	Revenue Delivery Charges				$408,574		$409,175
21							
22	Fuel & Purchased Power		16,196,892		465,337	$0.028730	465,337
23	**TOTAL REVENUE**				**$873,911**		**$874,512**
24							$601
25	**TOTAL GS-31**	kWh	16,196,892				
26		Cust	42				
	LARGE GENERAL SERVICE - GS-13						
27	Customer Charge		7,200	$1,675.88		371.880	$2,677,536
28	Summer Demand		720,000	$0.00		10.352	$7,453,440
29	Winter Demand		720,000	$0.00		10.352	$7,453,440
30	Summer Demand All Additional kW		916,524	$6.52		10.352	$9,487,856
31	Winter Demand All Additional kW		916,524	$6.52		10.352	$9,487,856
32	Summer kWhs		693,084,147	$0.063744		0.025656	$17,781,767
33	Winter kWhs		511,143,990	$0.060556		0.023910	$12,221,453
34	Revenue Delivery Charges				$66,562,476		$66,563,349
	Fuel & Purchased Power			1,636,524			
35	Summer		693,084,147	1,636,524	22,562,661	0.032554	22,562,661
36	Winter		511,143,990		12,806,202	0.025054	12,806,202
37	**TOTAL REVENUE**				**$101,931,338**		**$101,932,211**

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TUCSON ELECTRIC POWER COMPANY
GENERAL SERVICE BUNDLED PROOF OF REVENUE
TEST YEAR ENDED DECEMBER 31, 2006
PER SETTLEMENT - 6% OVERALL INCREASE

Line No.	Pricing Plan		Adjusted Booked Billing Determinants	Existing Rates	Total Adjusted Revenue Requirement	Proposed Rate	Proposed Revenue
38							$873
39	TOTAL GS-13	kWh	1,204,228,137				
40		Cust	600				
	PRS-13 - CONTRACT						
41	Revenue Delivery Charges				$577,959		$577,959
42	Fuel & Purchased Power		4,759,193		136,732	0.028730	136,732
43	TOTAL REVENUE				$714,690		$714,690
44							$0
45	TOTAL PRS-13	kWh	4,759,193				
46		Cust	2				

TUCSON ELECTRIC POWER COMPANY
GENERAL SERVICE BUNDLED PROOF OF REVENUE
TEST YEAR ENDED DECEMBER 31, 2006
PER SETTLEMENT - 6% OVERALL INCREASE

Line No.	Pricing Plan		Adjusted Booked Billing Determinants	Existing Rates	Total Adjusted Revenue Requirement	Proposed Rate	Proposed Revenue
	LARGE GENERAL SERVICE TIME OF USE - GS-85AF - FROZEN						
1	Customers		372	$98.01		371.880	$138,339
2	Summer On-peak Demand		36,000	$7.50		7.950	$286,200
3	Summer Off-peak Demand					3.975	
4	Summer Shoulder-peak Demand					5.258	
5	Winter On-peak Demand		36,000	$4.96		5.258	$189,274
6	Winter Off-peak Demand					2.629	
7	Summer Demand All Additional kW		21,140	$7.50		7.950	$168,066
8	Winter Demand All Additional kW		11,970	$4.96		5.258	$62,940
	Summer						
9	On Peak kWhs		6,151,695	$0.069587		0.053290	$327,824
10	Off Peak kWhs		29,592,895	$0.061746		0.036667	$1,085,083
11	Shoulder Peak kWhs		2,126,538	$0.065667		0.044980	$95,652
	Winter						
12	On Peak kWhs		5,802,304	$0.065667		0.044980	$260,988
13	Off Peak kWhs		22,212,312	$0.057826		0.028356	$629,852
14	Revenue Delivery Charges				$3,244,455		$3,244,217
	Fuel & Purchased Power						
15	Summer On Peak kWhs		8,278,232		467,323	0.056452	467,323
16	Summer Off Peak kWhs		29,592,895		708,809	0.023952	708,809
17	Winter On Peak kWhs		5,802,304		228,268	0.039341	228,268
18	Winter Off Peak kWhs		22,212,312		429,608	0.019341	429,608
19	**TOTAL REVENUE**				$5,078,464		$5,078,225
20							-$239
21	**TOTAL GS-85A**	kWh	65,885,743				
22		Cust	31				
	LARGE GENERAL SERVICE TIME OF USE FROZEN - GS-85F - FROZEN						
23	Customers		240	$94.60		$371.880	$89,251
24	Summer On-peak Demand		24,000	$16.34		$17.320	$415,680
25	Summer Off-peak Demand					$8.660	
26	Summer Shoulder-peak Demand					$11.455	
27	Winter On-peak Demand		24,000	$9.10		$9.646	$231,504
28	Winter Off-peak Demand					$4.823	
29	Summer Demand All Additional kW		36,047	$16.34		$17.320	$624,348
30	Winter Demand All Additional kW		23,889	$9.10		$9.646	$230,433
	Summer						
31	On Peak kWhs		5,748,531	$0.104973		$0.083765	$481,526
32	Off Peak kWhs		27,935,990	$0.031320		$0.005693	$159,040
33	Shoulder Peak kWhs		1,956,514	$0.076808		$0.053910	$105,476
	Winter						
34	On Peak kWhs		5,677,051	$0.076808		$0.053910	$306,050
35	Off Peak kWhs		21,277,580	$0.031320		$0.005693	$121,133
36	Revenue Delivery Charges				$2,764,585		$2,764,441

TUCSON ELECTRIC POWER COMPANY
GENERAL SERVICE BUNDLED PROOF OF REVENUE
TEST YEAR ENDED DECEMBER 31, 2006
PER SETTLEMENT - 6% OVERALL INCREASE

Line No.	Pricing Plan		Adjusted Booked Billing Determinants	Existing Rates	Total Adjusted Revenue Requirement	Proposed Rate	Proposed Revenue
	Fuel & Purchased Power						
37	Summer On Peak kWhs		7,705,045		434,965	$0.056452	434,965
38	Summer Off Peak kWhs		27,935,990		669,123	$0.023952	669,123
39	Winter On Peak kWhs		5,677,051		223,341	$0.039341	223,341
40	Winter Off Peak kWhs		21,277,580		411,530	$0.019341	411,530
41	TOTAL REVENUE				$4,503,544		$4,503,400
42							-$144
43	TOTAL GS-85F	kWh	62,595,666			0.140150	
44		Cust	20				

TOTAL GENERAL SERVICE REVENUE		$327,324,550	$327,326,477
TOTAL GENERAL SERVICE KWHS	3,314,379,658		
TOTAL GENERAL SERVICE CUSTOMERS	34,743		

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TUCSON ELECTRIC POWER COMPANY
LARGE LIGHT & POWER SERVICE BUNDLED PROOF OF REVENUE
TEST YEAR ENDED DECEMBER 31, 2006
PER SETTLEMENT - 6% OVERALL INCREASE

Line No.	Pricing Plan		Adjusted Booked Billing Determinants	Existing Rates	Total Adjusted Revenue Requirement	Proposed Rate	Proposed Revenue
	LARGE LIGHT AND POWER - LLP-14 -						
1	Customer Charge		96	0.00		500.00	$48,000
2	Demand		781,110	$9.97		16.155	$12,618,839
3	Demand		542,806	$9.97		16.155	$8,769,024
4	Summer kWhs		330,927,434	$0.046001		0.000433	$143,292
5	Witner kWhs		283,169,858	$0.043701		0.000433	$122,613
6	Revenue Delivery Charges				$21,701,502		$21,701,767
	Fuel & Purchased Power						
7	Summer		330,927,434		10,780,623	0.032577	10,780,623
8	Winter		283,169,858		7,101,051	0.025077	7,101,051
9	TOTAL REVENUE				$39,583,175		$39,583,441
10							$265
11	TOTAL LLP-14	kWh	614,097,291				
12		Cust	8				

Line No.	Pricing Plan		Adjusted Booked Billing Determinants	Existing Rates	Total Adjusted Revenue Requirement	Proposed Rate	Proposed Revenue
	PRS-14 - CONTRACT						
13	Revenue Delivery Charges				$5,297,811		$5,297,811
14	Fuel & Purchased Power		93,605,189		2,584,439	0.027610	2,584,439
15	TOTAL REVENUE				$7,882,251		$7,882,251
16							$0
17	TOTAL PRS-14	kWh	93,605,189				
18		Cust	1				

TUCSON ELECTRIC POWER COMPANY
LARGE LIGHT & POWER SERVICE BUNDLED PROOF OF REVENUE
TEST YEAR ENDED DECEMBER 31, 2006
PER SETTLEMENT - 6% OVERALL INCREASE

Line No.	Pricing Plan		Adjusted Booked Billing Determinants	Existing Rates	Total Adjusted Revenue Requirement	Proposed Rate	Proposed Revenue
	LARGE LIGHT AND POWER TIME OF USE - LLP-90A - FROZEN						
1	Customer Charge		12			500.00	$6,000
2	Summer On Peak kW		41,718	$10.95		25.581	$1,067,188
3	Summer Off Peak kW					10.581	
4	Summer Shoulder Peak kW					18.081	
5	Winter On Peak kW		41,369	$8.99		21.581	$892,784
6	Winter Off Peak kW					10.581	
7	Summer On Peak kWhs		4,368,214	$0.058806		0.006203	$27,095
8	Summer Off Peak kWhs		25,419,192	$0.041654		0.006203	$157,667
9	Summer Shoulder Peak kWhs		1,744,779	$0.049005		0.006203	$10,822
10	Witner On Peak kWhs		5,896,039	$0.058806		0.006203	$36,571
11	Winter Off Peak kWhs		25,100,381	$0.041654		0.006203	$155,690
12	Revenue Delivery Charges				$2,353,318		$2,353,818
	Fuel & Purchased Power						
13	Summer On Peak kWhs		6,112,993		323,885	0.052983	323,885
14	Summer Off Peak kWhs		25,419,192		520,661	0.020483	520,661
15	Winter On Peak kWhs		5,896,039		210,035	0.035623	210,035
16	Witner Off Peak kWhs		25,100,381		392,143	0.015623	392,143
17	TOTAL REVENUE				$3,800,042		$3,800,542
18							$500
19	TOTAL LLP-90A	kWh	62,528,604.78				
20		Cust	1				
	LARGE LIGHT AND POWER TIME OF USE FROZEN LLP-90F - FROZEN						
21	Customer Charge		48			500.000	$24,000
22	Summer On Peak kW		150,506	$20.34		25.702	$3,868,305
23	Summer Off Peak kW					13.202	
24	Summer Shoulder Peak kW					19.452	
25	Winter On Peak kW		133,207	$10.73		21.702	$2,890,858
26	Winter Off Peak kW					9.202	
27	Summer On Peak kWhs		15,169,458	$0.083541		0.000433	$6,568
28	Summer Off Peak kWhs		77,504,261	$0.028002		0.000433	$33,559
29	Summer Shoulder Peak kWhs		5,686,028	$0.042003		0.000433	$2,462
30	Witner On Peak kWhs		16,976,026	$0.042003		0.000433	$7,351
31	Winter Off Peak kWhs		63,378,144	$0.028002		0.000433	$27,443
35	Revenue Delivery Charges				$6,860,727		$6,860,547
	Fuel & Purchased Power						
36	Summer On Peak kWhs		20,855,486		1,104,986	0.052983	1,104,986
37	Summer Off Peak kWhs		77,504,261		1,587,520	0.020483	1,587,520
38	Winter On Peak kWhs		16,976,026		604,737	0.035623	604,737
39	Witner Off Peak kWhs		63,378,144		990,157	0.015623	990,157
40	TOTAL REVENUE				$11,148,126		$11,147,946
41							-$180

DECISION NO. ______

TUCSON ELECTRIC POWER COMPANY
LARGE LIGHT & POWER SERVICE BUNDLED PROOF OF REVENUE
TEST YEAR ENDED DECEMBER 31, 2006
PER SETTLEMENT - 6% OVERALL INCREASE

Line No.	Pricing Plan		Adjusted Booked Billing Determinants	Existing Rates	Total Adjusted Revenue Requirement	Proposed Rate	Proposed Revenue
42	TOTAL LLP-90F	kWh	178,713,918				
43		Cust	4				
44	TOTAL LARGE LIGHT AND POWER SERVICE REVENUE				$62,413,594		$62,414,179
45	TOTAL LARGE LIGHT AND POWER KWHS		948,945,003				
46	TOTAL LARGE LIGHT AND POWER CUSTOMERS		14				

TUCSON ELECTRIC POWER COMPANY
PUBLIC AUTHORITY SERVICE BUNDLED PROOF OF REVENUE
TEST YEAR ENDED DECEMBER 31, 2006
PER SETTLEMENT - 6% OVERALL INCREASE

Line No.	Pricing Plan		Adjusted Booked Billing Determinants	Existing Rates	Total Adjusted Revenue Requirement	Proposed Rate	Proposed Revenue
	MUNICIPAL SERVICE PS-40						
1	Energy kWh Summer		58,667,833	$0.082463		$0.057530000	$3,375,160
2	Energy kWh Winter		42,694,636	$0.078340		$0.053159000	2,269,604
3	Revenue Delivery Charges				$5,644,692		$5,644,765
4	Fuel & Purchased Power						
5	Summer		58,667,833		1,891,744	$0.032245000	1,891,744
6	Winter		42,694,636		1,056,479	$0.024745000	1,056,479
7	**TOTAL REVENUE**				**$8,592,915**		**$8,592,988**
							$73
8	**TOTAL PS-40**	kWh	101,362,469				
9		Cust	3				
	MUNICIPAL WATER PUMPING PS-43						
10	Energy kWh Summer		33,365,680	$0.082463		$0.060347000	$2,013,519
11	Energy kWh Winter		25,062,900	$0.078340		$0.055731000	1,396,780
12	***PS-45&46 Interruptible Service***						
13	Energy kWh Summer		35,724,522	$0.051500		$0.027281000	974,601
14	Energy kWh Winter		29,743,473	$0.050208		$0.025911000	770,683
15	Revenue Delivery Charges				$5,155,606		$5,155,583
16	*Fuel & Purchased Power*						
17	Energy kWh Summer		33,365,680		996,566	$0.029868000	996,566
18	Energy kWh Winter		25,062,900		560,607	$0.022368000	560,607
19	***PS-45&46 Interruptible Service***						
20	Energy kWh Summer		35,724,522		1,067,020	$0.029868000	1,067,020
21	Energy kWh Winter		29,743,473		665,302	$0.022368000	665,302
22	**TOTAL REVENUE**				**$8,445,101**		**$8,445,078**
23							-$23
24	**TOTAL PS-43**	kWh	123,896,575				
		Cust	32				
25	**TOTAL PA SERVICE REVENUE**				**$17,038,015**		**$17,038,066**
26	**TOTAL PA SERVICE KWHS**		225,259,044				
27	**TOTAL PA SERVICE CUSTOMERS**		35				

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TUCSON ELECTRIC POWER COMPANY
LIGHTING SERVICE BUNDLED PROOF OF REVENUE
TEST YEAR ENDED DECEMBER 31, 2006
PER SETTLEMENT - 6% OVERALL INCREASE

Line No.	Pricing Plan			Adjusted Booked Billing Determinants	Existing Rates	Total Adjusted Revenue Requirement	Proposed Rate	Proposed Revenue
	TRAFFIC SIGNALS AND STREET LIGHTING PS-41&47							
1	Deliver Charge			33,727,523	$0.067861			
2	Revenue Delivery Charges					$1,533,200	$0.045505	1,534,771
3	Fuel & Purchased Power			33,727,523		870,743	$0.025817	870,743
4	TOTAL REVENUE							
5						$2,403,943		$2,405,514
6		kWh		33,727,523				$1,571
7		Cust		8				
	LIGHTING PS-50, PS-51, and PS-52		SALES	ANNUAL UNITS				
8	Per 100 Watt		3,615,724	120,300	$11.26	$889,979	$7.390	$889,017
9	Per 250 Watt		1,456,208	19,380	$16.90	$215,187	$11.092	$214,963
10	Per 400 Watt		2,112,088	17,568	$26.07	$300,912	$17.110	$300,588
11	Per One Pole			3,960	$3.93	$10,225	$2.582	$10,225
12	Underground Service			47,892	$21.33	$671,165	$14.014	$671,158
13	55OH - new		8,331	504	$11.26	$3,729	$7.390	$3,725
14	55P -new		18,250	1,104	$11.26	$8,167	$7.390	$8,159
15	55UG -new		24,994	1,512	$11.26	$11,186	$7.390	$11,174
16	70UG -new		52,009	2,472	$11.26	$18,288	$7.390	$18,268
17			7,287,604	214,692				
18	Revenue Delivery Charges					$2,128,837		2,127,277
19								
20	Fuel & Purchased Power					188,144	0.025817	188,144
21								
22	TOTAL REVENUE					$2,316,981		$2,315,421
								-$1,560
23	LIGHTING PS-50, PS-51, and PS-52	kWh		7,287,604				
24		Cust		18				
25		Hours		301				
	LIGHTING SERVICE SUMMARY							
26	TOTAL LIGHTING SERVICE REVENUE					$4,720,924		$4,720,935
27	TOTAL LIGHTING SERVICE REVENUE KWHS			41,015,127				
28	TOTAL LIGHTING SERVICE CUSTOMERS			26				

Rate Increase	$ Per Customer Month Fuel&PP	TOTAL $/ CUSTOMER	TOTAL ANNUAL REVENUE
5.03%			
	0.776000	8.166	982,370
	1.940000	13.032	252,560
	3.104000	20.214	355,120
		2.582	10,225
		14.014	671,158
	0.427000	7.817	3,940
	0.427000	7.817	8,630
	0.427000	7.817	11,819
	0.543000	7.933	19,610
			0
			$2,315,432.14
-28.5%			

TUCSON ELECTRIC POWER COMPANY
Average Base Cost of Fuel and Purchased Power

FERC Account	TEP Adjusted Total	TEP Adjusted ACC Jurisdiction Amount	Jurisdictional Percent	Adjusted Total Per Settlement	Adjusted ACC Jurisdictional
501	$ 239,090,289.98	$ 214,137,539.47	0.895634614	$ 216,920,289.98	$ 194,281,320
547	$ 26,864,965.52	$ 24,061,193.01	0.895634613	$ 26,864,965.52	$ 24,061,193
565	$ 4,771,517.47	$ 4,510,725.20	0.945343956	$ 4,771,517.47	$ 4,510,725
555-D	$ 30,633,600.00	$ 28,959,288.61	0.945343956	$ 13,739,600.00	$ 12,988,648
555-E	$ 40,035,093.60	$ 35,856,815.58	0.895634613	$ 37,330,093.60	$ 33,434,124
TOTAL	$ 341,395,466.57	$ 307,525,561.87		$ 299,626,466.57	$ 269,276,010.00
Total cost of fuel and PP in PPFAC Includible Accounts		$ 307,525,561.87			**$ 269,276,010.00**
Sales, Adjusted kWhs		9,318,849,104			9,318,849,104

Base Cost of Fuel and Purchased Power per TEP	$ 0.033000 $/kWH	**Average Base Cost of Fuel and PP**	$ 0.028896 $/kWH

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TUCSON ELECTRIC POWER COMPANY
Comparison of Present and Proposed Depreciation Accrual Rates

Account Description		Present Rem. Life	Present Fut. Net Salvage	Present Accrual Rate	New Avg. Life	New Rem. Life	New Net Salvage	New Reserve Ratio	New Accrual Rate
					Local Generation				
STEAM PRODUCTION (by Unit)									
Sundt Unit 1									
311.00	Structures and Improvements			0.58%		21.81	-34.7%	74.15%	2.78%
312.00	Boiler Plant Equipment			2.19%		21.84	-34.9%	61.42%	3.36%
314.00	Turbogenerator Units			0.65%		21.81	-34.7%	74.11%	2.78%
315.00	Accessory Electric Equipment			1.00%		21.82	-34.8%	65.24%	3.19%
316.00	Miscellaneous Power Plant Equipment			2.30%		21.83	-34.8%	58.63%	3.49%
317.00	Asset Retirement Costs								
	Total Sundt Unit 1			1.53%		21.83	-34.8%	66.37%	3.13%
Sundt Unit 2									
311.00	Structures and Improvements			0.62%		23.68	-34.5%	67.87%	2.81%
312.00	Boiler Plant Equipment			2.45%		23.71	-34.6%	50.15%	3.56%
314.00	Turbogenerator Units			0.94%		23.68	-34.5%	68.32%	2.79%
315.00	Accessory Electric Equipment			1.34%		23.71	-34.6%	52.93%	3.44%
316.00	Miscellaneous Power Plant Equipment			2.77%		23.72	-34.6%	41.76%	3.91%
317.00	Asset Retirement Costs								
	Total Sundt Unit 2			1.81%		23.70	-34.6%	56.78%	3.28%
Sundt Unit 3									
311.00	Structures and Improvements			0.68%		24.61	-34.4%	78.78%	2.26%
312.00	Boiler Plant Equipment			1.24%		24.64	-34.5%	64.72%	2.83%
314.00	Turbogenerator Units			1.91%		24.65	-34.5%	52.69%	3.32%
315.00	Accessory Electric Equipment			3.06%		24.67	-34.6%	33.83%	4.08%
316.00	Miscellaneous Power Plant Equipment			2.11%		24.64	-34.5%	60.70%	3.00%
317.00	Asset Retirement Costs					24.68		5.56%	3.83%
	Total Sundt Unit 3			1.84%		24.65	-34.1%	53.71%	3.26%
Sundt Unit 4									
311.00	Structures and Improvements			9.36%		4.47	-36.6%	40.75%	21.44%
312.00	Boiler Plant Equipment			13.20%		4.47	-36.6%	35.99%	22.51%
314.00	Turbogenerator Units			11.41%		4.47	-36.6%	34.32%	22.88%
315.00	Accessory Electric Equipment			7.35%		4.47	-36.6%	49.36%	19.52%
316.00	Miscellaneous Power Plant Equipment			11.06%		4.47	-36.6%	36.69%	22.35%
317.00	Asset Retirement Costs								
	Total Sundt Unit 4			12.27%		4.47	-36.6%	35.81%	22.55%
Sundt Coal Conversion									
311.00	Structures and Improvements			3.58%		4.47	-36.6%	81.31%	12.37%
312.00	Boiler Plant Equipment			3.76%		4.47	-36.6%	80.86%	12.47%
314.00	Turbogenerator Units			3.51%		4.47	-36.6%	81.65%	12.29%
315.00	Accessory Electric Equipment			5.27%		4.47	-36.6%	75.12%	13.75%
316.00	Miscellaneous Power Plant Equipment			3.40%		4.47	-36.6%	81.65%	12.29%
317.00	Asset Retirement Costs								
	Total Sundt Coal Conversion			3.90%		4.47	-36.6%	80.30%	12.60%

TUCSON ELECTRIC POWER COMPANY
Comparison of Present and Proposed Depreciation Accrual Rates

	Present			New				
Account Description	Rem. Life	Fut. Net Salvage	Accrual Rate	Avg. Life	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
Sundt Coal Handling								
311.00 Structures and Improvements								
312.00 Boiler Plant Equipment			19.22%		4.47	-36.6%	6.99%	29.00%
314.00 Turbogenerator Units								
315.00 Accessory Electric Equipment			1.30%		4.47	-36.6%	3.92%	29.68%
316.00 Miscellaneous Power Plant Equipment								
317.00 Asset Retirement Costs								
Total Sundt Coal Handling			15.84%		4.47	-36.6%	6.41%	29.13%
OTHER PRODUCTION (by Unit)								
DeMoss Petrie Gas Unit 1								
341.00 Structures and Improvements			2.18%		37.52	-27.9%	13.08%	3.06%
342.00 Fuel Holders and Accessories			2.18%		37.52	-27.9%	13.08%	3.06%
343.00 Prime Movers								
344.00 Generators			2.18%		37.52	-27.9%	13.08%	3.06%
345.00 Accessory Electric Equipment			2.18%		37.52	-27.9%	13.08%	3.06%
346.00 Miscellaneous Power Plant Equipment			2.28%		37.53	-27.9%	10.71%	3.12%
Total DeMoss Petrie Gas Unit 1			2.18%		37.52	-27.9%	13.06%	3.06%
Sundt Gas Unit 1								
341.00 Structures and Improvements			0.07%		10.36	-30.2%	87.27%	4.14%
342.00 Fuel Holders and Accessories			4.14%		10.36	-30.2%	64.00%	6.39%
343.00 Prime Movers			0.07%		10.36	-30.2%	47.37%	8.00%
344.00 Generators			0.57%		10.35	-30.2%	94.65%	3.43%
345.00 Accessory Electric Equipment			1.04%		10.36	-30.2%	87.86%	4.09%
346.00 Miscellaneous Power Plant Equipment			0.07%		10.35	-30.2%	105.09%	2.43%
Total Sundt Gas Unit 1			0.65%		10.35	-30.2%	92.97%	3.59%
Sundt Gas Unit 2								
341.00 Structures and Improvements			0.76%		10.36	-30.2%	83.57%	4.50%
342.00 Fuel Holders and Accessories			4.44%		10.36	-30.2%	61.30%	6.65%
343.00 Prime Movers			0.77%		10.36	-30.2%	45.37%	8.19%
344.00 Generators			1.34%		10.36	-30.2%	86.30%	4.24%
345.00 Accessory Electric Equipment			2.16%		10.36	-30.2%	79.66%	4.88%
346.00 Miscellaneous Power Plant Equipment			0.76%		10.35	-30.2%	99.99%	2.92%
Total Sundt Gas Unit 2			1.46%		10.36	-30.2%	84.73%	4.39%
North Loop Gas Unit 1								
341.00 Structures and Improvements			4.10%		10.36	-30.2%	60.62%	6.72%
342.00 Fuel Holders and Accessories								
343.00 Prime Movers			2.09%		10.36	-30.2%	45.63%	8.16%
344.00 Generators			1.20%		10.36	-30.2%	85.80%	4.29%
345.00 Accessory Electric Equipment			3.67%		10.36	-30.2%	64.49%	6.34%
346.00 Miscellaneous Power Plant Equipment			4.21%		10.36	-30.2%	62.10%	6.57%
Total North Loop Gas Unit 1			1.98%		10.36	-30.2%	78.77%	4.97%

TUCSON ELECTRIC POWER COMPANY
Comparison of Present and Proposed Depreciation Accrual Rates

	Present			New				
Account Description	Rem. Life	Fut. Net Salvage	Accrual Rate	Avg. Life	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
North Loop Gas Unit 2								
341.00 Structures and Improvements			1.26%		10.35	-10.7%	76.04%	3.35%
342.00 Fuel Holders and Accessories								
343.00 Prime Movers			1.83%		10.36	-30.2%	46.27%	8.10%
344.00 Generators			0.69%		10.35	-30.2%	93.72%	3.52%
345.00 Accessory Electric Equipment			1.82%		10.36	-30.2%	80.78%	4.77%
346.00 Miscellaneous Power Plant Equipment			0.01%		10.35	-30.2%	103.64%	2.57%
Total North Loop Gas Unit 2			0.84%		10.35	-29.3%	90.89%	3.70%
North Loop Gas Unit 3								
341.00 Structures and Improvements			1.25%		10.35	-30.2%	87.02%	4.17%
342.00 Fuel Holders and Accessories								
343.00 Prime Movers			2.63%		10.36	-30.2%	45.02%	8.22%
344.00 Generators			0.75%		10.35	-30.2%	92.41%	3.65%
345.00 Accessory Electric Equipment			1.85%		10.36	-30.2%	78.70%	4.97%
346.00 Miscellaneous Power Plant Equipment			0.01%		10.35	-30.2%	100.84%	2.84%
Total North Loop Gas Unit 3			0.91%		10.35	-30.2%	89.97%	3.89%
North Loop Gas Unit 4								
341.00 Structures and Improvements			2.27%		37.53	-27.9%	16.26%	2.97%
342.00 Fuel Holders and Accessories			2.20%		37.52	-27.9%	11.87%	3.09%
343.00 Prime Movers								
344.00 Generators			2.19%		37.52	-27.9%	12.83%	3.07%
345.00 Accessory Electric Equipment			2.20%		37.52	-27.9%	15.37%	3.00%
346.00 Miscellaneous Power Plant Equipment			2.19%		37.52	-27.9%	20.88%	2.85%
Total North Loop Gas Unit 4			2.19%		37.52	-27.9%	13.04%	3.06%

TUCSON ELECTRIC POWER COMPANY
Comparison of Present and Proposed Depreciation Accrual Rates

Account Description	Present			New				
	Rem. Life	Fut. Net Salvage	Accrual Rate	Avg. Life	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
	Non Local Generation							
STEAM PRODUCTION (by Unit)								
Four Corners Unit 4								
310.00 Rights-of-Way								
311.00 Structures and Improvements	26.50		0.90%		23.71	-40.5%	84.84%	2.35%
312.00 Boiler Plant Equipment	26.51		0.68%		23.71	-40.6%	82.51%	2.45%
314.00 Turbogenerator Units	26.50		0.66%		23.72	-40.6%	70.72%	2.95%
315.00 Accessory Electric Equipment	26.47		0.43%		23.68	-40.5%	103.54%	1.56%
316.00 Miscellaneous Power Plant Equipment	26.53		1.81%		23.73	-40.6%	51.29%	3.76%
317.00 Asset Retirement Cost	26.47		0.41%		23.67		76.98%	0.97%
Total Four Corners Unit 4			0.72%		23.71	-40.6%	80.07%	2.55%
Four Corners Unit 5								
310.00 Rights-of-Way								
311.00 Structures and Improvements	26.50		0.98%		23.70	-40.5%	85.96%	2.30%
312.00 Boiler Plant Equipment	26.51		0.78%		23.71	-40.5%	79.99%	2.55%
314.00 Turbogenerator Units	26.50		0.87%		23.71	-40.5%	81.06%	2.51%
315.00 Accessory Electric Equipment	26.48		0.56%		23.69	-40.5%	99.34%	1.74%
316.00 Miscellaneous Power Plant Equipment	26.53		1.80%		23.73	-40.6%	50.10%	3.81%
317.00 Asset Retirement Cost	26.47		0.52%		23.67		73.63%	1.11%
Total Four Corners Unit 5			0.83%		23.71	-40.5%	79.19%	2.58%
Navajo Unit 1								
310.00 Rights-of-Way								
311.00 Structures and Improvements	21.83		1.60%		18.99	-41.1%	73.93%	3.54%
312.00 Boiler Plant Equipment	21.85		2.25%		19.01	-41.1%	52.62%	4.65%
314.00 Turbogenerator Units	21.84		1.61%		19.01	-41.1%	59.59%	4.29%
315.00 Accessory Electric Equipment	21.82		1.28%		18.99	-41.1%	78.57%	3.29%
316.00 Miscellaneous Power Plant Equipment	21.82		1.46%		18.99	-41.1%	75.12%	3.47%
317.00 Asset Retirement Cost	21.82		1.11%		18.98		56.70%	2.28%
Total Navajo Unit 1			2.02%		19.01	-41.1%	57.45%	4.40%
Navajo Unit 2								
310.00 Rights-of-Way								
311.00 Structures and Improvements	21.84		1.26%		19.00	-41.1%	65.74%	3.97%
312.00 Boiler Plant Equipment	21.84		2.25%		19.00	-41.1%	58.14%	4.37%
314.00 Turbogenerator Units	21.84		1.88%		19.00	-41.1%	57.01%	4.43%
315.00 Accessory Electric Equipment	21.84		1.60%		19.00	-41.1%	65.86%	3.96%
316.00 Miscellaneous Power Plant Equipment	21.83		1.57%		18.99	-41.1%	68.96%	3.80%
317.00 Asset Retirement Cost	21.82		1.20%		18.98		54.29%	2.41%
Total Navajo Unit 2			2.08%		19.00	-41.1%	59.01%	4.32%
Navajo Unit 3								
310.00 Rights-of-Way								
311.00 Structures and Improvements	21.84		2.00%		19.00	-41.1%	64.88%	4.01%
312.00 Boiler Plant Equipment	21.84		2.15%		19.01	-41.1%	55.06%	4.53%
314.00 Turbogenerator Units	21.83		1.53%		19.00	-41.1%	59.61%	4.29%
315.00 Accessory Electric Equipment	21.83		1.86%		18.99	-41.1%	65.75%	3.97%
316.00 Miscellaneous Power Plant Equipment	21.83		0.10%		18.99	-41.1%	68.18%	3.84%
317.00 Asset Retirement Cost	21.82		1.34%		18.99		52.82%	2.48%
Total Navajo Unit 3			1.98%		19.01	-41.1%	57.99%	4.38%

TUCSON ELECTRIC POWER COMPANY
Comparison of Present and Proposed Depreciation Accrual Rates

		Present			New				
Account Description		Rem. Life	Fut. Net Salvage	Accrual Rate	Avg. Life	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
Navajo Common									
310.00	Rights-of-Way	21.82		0.40%		18.99		55.04%	2.37%
311.00	Structures and Improvements	21.86		3.06%		19.01	-41.2%	42.32%	5.20%
312.00	Boiler Plant Equipment	21.86		3.17%		19.01	-41.2%	38.58%	5.40%
314.00	Turbogenerator Units					19.02	-41.2%	19.40%	6.40%
315.00	Accessory Electric Equipment	21.86		3.26%		19.02	-41.2%	28.58%	5.92%
316.00	Miscellaneous Power Plant Equipment	21.86		3.14%		19.01	-41.2%	40.36%	5.30%
317.00	Asset Retirement Cost								
Total Navajo Common				3.11%		19.01	-41.2%	40.48%	5.30%
San Juan Unit 1									
310.00	Rights-of-Way								
311.00	Structures and Improvements	31.10		0.75%		28.34	-39.9%	79.23%	2.14%
312.00	Boiler Plant Equipment	31.12		1.00%		28.35	-40.0%	69.90%	2.47%
314.00	Turbogenerator Units	31.11		1.04%		28.35	-40.0%	70.68%	2.45%
315.00	Accessory Electric Equipment	31.10		0.87%		28.34	-40.0%	74.44%	2.31%
316.00	Miscellaneous Power Plant Equipment	31.10		0.75%		28.35	-40.0%	71.32%	2.42%
317.00	Asset Retirement Cost	31.08		0.97%		28.32		60.62%	1.39%
Total San Juan Unit 1				0.98%		28.35	-40.0%	70.99%	2.43%
San Juan Unit 2									
310.00	Rights-of-Way								
311.00	Structures and Improvements	28.34		0.90%		25.56	-40.3%	81.81%	2.29%
312.00	Boiler Plant Equipment	28.36		1.11%		25.58	-40.3%	72.38%	2.66%
314.00	Turbogenerator Units	28.36		1.23%		25.58	-40.3%	68.42%	2.81%
315.00	Accessory Electric Equipment	28.34		0.73%		25.56	-40.3%	81.79%	2.29%
316.00	Miscellaneous Power Plant Equipment	28.34		0.91%		25.56	-40.3%	82.46%	2.26%
317.00	Asset Retirement Cost	28.32		0.77%		25.54		64.82%	1.38%
Total San Juan Unit 2				1.09%		25.58	-40.3%	73.04%	2.63%
San Juan Common									
310.00	Rights-of-Way								
311.00	Structures and Improvements								
312.00	Boiler Plant Equipment	31.16		2.33%		28.39	-40.1%	38.37%	3.58%
314.00	Turbogenerator Units								
315.00	Accessory Electric Equipment								
316.00	Miscellaneous Power Plant Equipment								
317.00	Asset Retirement Cost								
Total San Juan Common				2.33%		28.39	-40.1%	38.37%	3.58%
Springerville Unit 1									
310.00	Rights-of-Way								
311.00	Structures and Improvements	11.33		-1.24%		8.41	-42.4%	31.78%	13.15%
312.00	Boiler Plant Equipment	11.33		7.40%		8.41	-42.4%	19.54%	14.61%
314.00	Turbogenerator Units	11.33		6.97%		8.41	-42.4%	25.29%	13.93%
315.00	Accessory Electric Equipment	11.33		7.08%		8.41	-42.4%	16.63%	14.95%
316.00	Miscellaneous Power Plant Equipment	11.33		6.25%		8.41	-42.4%	20.89%	14.45%
317.00	Asset Retirement Cost								
Total Springerville Unit 1				7.15%		8.41	-42.4%	20.97%	14.44%

TUCSON ELECTRIC POWER COMPANY
Comparison of Present and Proposed Depreciation Accrual Rates

		Present			New				
	Account Description	Rem. Life	Fut. Net Salvage	Accrual Rate	Avg. Life	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
Springerville Unit 2									
310.00	Rights-of-Way								
311.00	Structures and Improvements	43.70		1.57%		41.03	-38.4%	35.43%	2.51%
312.00	Boiler Plant Equipment	43.71		1.49%		41.05	-38.5%	33.92%	2.55%
314.00	Turbogenerator Units	43.70		1.50%		41.04	-38.5%	34.54%	2.53%
315.00	Accessory Electric Equipment	43.70		1.50%		41.03	-38.4%	35.47%	2.51%
316.00	Miscellaneous Power Plant Equipment	43.70		1.51%		41.04	-38.5%	33.77%	2.55%
317.00	Asset Retirement Cost								
	Total Springerville Unit 2			1.50%		41.04	-38.5%	34.29%	2.54%
Springerville Unit 1 Common									
310.00	Rights-of-Way	11.33		5.38%		8.41		42.57%	6.83%
311.00	Structures and Improvements	11.33		4.61%		8.41	-42.4%	57.19%	10.13%
312.00	Boiler Plant Equipment	11.33		6.91%		8.41	-42.4%	38.67%	12.33%
314.00	Turbogenerator Units	11.33		6.62%		8.41	-42.4%	41.88%	11.95%
315.00	Accessory Electric Equipment	11.33		6.99%		8.41	-42.4%	26.01%	13.84%
316.00	Miscellaneous Power Plant Equipment	11.33		5.26%		8.41	-42.4%	30.27%	13.33%
317.00	Asset Retirement Cost								
	Total Springerville Unit 1 Common			5.06%		8.41	-38.9%	52.64%	10.26%
Springerville Unit 2 Common									
310.00	Rights-of-Way	16.15		4.24%		13.26		38.93%	4.61%
311.00	Structures and Improvements	16.15		3.41%		13.26	-41.8%	52.37%	6.74%
312.00	Boiler Plant Equipment	16.15		4.53%		13.27	-41.9%	43.11%	7.44%
314.00	Turbogenerator Units	16.15		4.49%		13.27	-41.9%	39.18%	7.74%
315.00	Accessory Electric Equipment	16.15		3.25%		13.26	-41.8%	54.24%	6.60%
316.00	Miscellaneous Power Plant Equipment	16.15		3.86%		13.27	-41.9%	41.09%	7.60%
317.00	Asset Retirement Cost								
	Total Springerville Unit 2 Common			3.62%		13.26	-39.2%	50.05%	6.72%
Springerville Coal Handling									
310.00	Rights-of-Way								
311.00	Structures and Improvements								
312.00	Boiler Plant Equipment	11.33		4.69%		8.41	-42.4%	34.68%	12.81%
314.00	Turbogenerator Units								
315.00	Accessory Electric Equipment								
316.00	Miscellaneous Power Plant Equipment								
317.00	Asset Retirement Cost								
	Total Springerville Coal Handling			4.69%		8.41	-42.4%	34.68%	12.81%

		Other Production - Non Local							
Luna Facility									
317.00	Asset Retirement Cost					39.25	0.0%	1.06%	2.57%
341.00	Structures & Improvements					39.25	0.0%	1.82%	2.57%
342.00	Fuel Holders, Producers, & Accessories					39.25	0.0%	1.82%	2.57%
344.00	Generators					39.25	0.0%	1.82%	2.57%
346.00	Misc. Power Plant Equipment					39.25	0.0%	1.82%	2.57%

DECISION NO. ____________

TUCSON ELECTRIC POWER COMPANY
Comparison of Present and Proposed Depreciation Accrual Rates

Account	Account Description	Present Rem. Life	Present Fut. Net Salvage	Present Accrual Rate	New Avg. Life	New Rem. Life	New Net Salvage	New Reserve Ratio	New Accrual Rate
					Distribution				
DISTRIBUTION PLANT									
360.00	Rights-of Way			2.22%		43.78		37.61%	1.43%
361.00	Structures & Improvements		-10.0%	2.44%		44.83		26.99%	1.63%
362.00	Station Equipment		-19.0%	4.25%		46.02		33.01%	1.46%
364.00	Poles, Towers and Fixtures		-59.0%	5.48%		39.16		35.98%	1.63%
365.00	Overhead Conductors and Devices		-17.0%	3.66%		41.83		38.71%	1.47%
366.00	Underground Conduit		-40.0%	2.33%		43.44		38.11%	1.42%
367.00	Underground Conductors and Devices		33.0%	1.63%		32.32		38.89%	1.89%
368.OH	Line Transformers - Overhead		-15.0%	3.38%		26.12		51.83%	1.84%
358.UG	Line Transformers - Underground		-15.0%	3.38%		23.28		41.39%	2.52%
369.OH	Services - Overhead		-34.0%	3.83%		28.70		53.55%	1.62%
369.UG	Services - Underground		-34.0%	3.83%		47.81		28.30%	1.50%
370.00	Meters		-25.0%	3.79%		19.73		40.91%	2.99%
373.00	Street Lighting and Signal Systems		-25.0%	4.46%		36.67		36.24%	1.74%
374.00	Asset Retirement Costs		-7.0%	3.2%		31.53		6.20%	2.97%
	Total Distribution Plant			3.35%		33.61		38.52%	1.82%
					General				
GENERAL PLANT									
Depreciable									
390.00	Structures & Improvements			2.22%		21.45		54.04%	2.14%
391.CM	Office Furn. And Equip. - Computer			20.00%		2.95		57.04%	14.56%
392.C0	Transportation Equipment - Class 0		16.0%	8.87%		14.63	15.0%	25.99%	4.03%
392.C1	Transportation Equipment - Class 1		16.0%	14.00%		5.10	15.0%	41.06%	8.62%
392.C2	Transportation Equipment - Class 2		21.0%	11.29%		4.99	25.0%	36.55%	7.71%
392.C3	Transportation Equipment - Class 3		18.0%	10.25%		7.07	15.0%	41.05%	6.22%
392.C4	Transportation Equipment - Class 4		9.0%	7.00%		9.80	10.0%	43.96%	4.70%
392.C5	Transportation Equipment - Class 5		1.0%	7.07%		10.67	5.0%	38.28%	5.32%
396.00	Power Operated Equipment			3.33%		11.46	5.0%	46.95%	4.19%
397.00	Communication Equipment			6.7%		18.13		32.72%	3.71%
	Total Depreciable			7.57%		9.53	4.0%	44.54%	5.31%
Amortizable									
391.FE	Office Furn. And Equip. - Furniture	← 24 Year Amortization →				← 24 Year Amortization →			
393.00	Stores Equipment	← 15 Year Amortization →				← 15 Year Amortization →			
394.00	Tools, Shop and Garage Equipment	← 17 Year Amortization →				← 17 Year Amortization →			
395.00	Laboratory Equipment	← 17 Year Amortization →				← 17 Year Amortization →			
398.00	Miscellaneous Equipment	← 20 Year Amortization →				← 20 Year Amortization →			
	Total Amortizable			8.00%		11.16		43.56%	5.06%
	Total General Plant			7.65%		9.75	3.3%	44.37%	5.26%
TOTAL INVESTMENT				3.96%		25.53	0.5%	39.34%	2.30%
NET SALVAGE									
108.02	Distribution	43.08	-50.0%			33.61	-15.0%	5.68%	0.28%
	Total net Salvage					33.61		5.68%	0.28%
TOTAL UTILITY				3.96%		25.53	-6.7%	44.22%	2.54%

DECISION NO. ______________

Tucson Electric Power Company
Purchased Power and Fuel Adjustment Clause
Plan of Administration

Table of Contents

1. GENERAL DESCRIPTION

This document describes the plan for administering the Purchased Power and Fuel Adjustment Clause ("PPFAC") the Arizona Corporation Commission ("Commission") approved for Tucson Electric Power Company ("TEP") in Decision No. XXXXX [DATE]. The PPFAC provides for the recovery of fuel and purchased power costs from the date of that decision forward.

The PPFAC described in this Plan of Administration ("POA") uses a forward-looking estimate of fuel and purchased power costs to set a rate that is then reconciled to actual costs experienced. This POA describes the application of the PPFAC.

2. DEFINITIONS

Applicable Interest - Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15. The interest rate is adjusted annually on the first business day of the calendar year.

Base Cost of Fuel and Purchased Power - An amount generally expressed as a rate per kWh, which reflects the fuel and purchased power cost embedded in the base rates as approved by the Commission in TEP's most recent rate case. The Base Cost of Fuel and Purchased Power revenue is the approved rate per kWh times the applicable sales volumes. Decision No. XXXXX set the base cost at $X.XXXX per kWh effective on [DATE].

Forward Component - An amount expressed as a rate per kWh charge that is updated annually on April 1 of each year and effective with the first billing cycle in April. The Forward Component for the PPFAC Year will adjust for the difference between the forecasted fuel and purchased power costs expressed as a rate per kWh less the Base Cost of Fuel and Purchase Power generally expressed as a rate per kWh embedded in TEP's base rates. The result of this calculation will equal the Forward Component, expressed as a rate per kWh.

Forward Component Tracking Account - An account that records on a monthly basis TEP's over/under-recovery of its actual costs of fuel and purchased power as compared to the actual Base Cost of Fuel and Purchased Power revenue and Forward Component revenue; plus Applicable Interest. The balance of this account as of the end of each PPFAC Year is, subject to periodic audit, reflected in the next True-Up Component calculation. TEP files the balances and supporting details underlying this Account with the Commission on a monthly basis via a monthly reporting requirement.

Fuel and Purchased Power Costs - The costs recorded for the fuel and purchased power used by TEP to serve both Total Native Load Energy Sales and Short Term Sales, less the costs associated with Mark-to-Market Accounting adjustments. Wheeling costs are included. Broker's fees and other expenses TEP records in Account 557 are not included.

Long Term Energy Sales - The portion of load from Total Native Load Energy Sales wholesale customers (currently Salt River Project, Tohono O'odham Utility Authority and Navajo Tribal Utility Authority) that is served by TEP, excluding the load served with Preference Power.

Mark-to-Market Accounting - Recording the value of qualifying commodity contracts to reflect their current market value relative to their actual cost.

PPFAC - The Purchased Power and Fuel Adjustment Clause approved by the Commission in Decision No. XXXXX, which is a combination of two rate components that track changes in the cost of obtaining power supplies based upon forward-looking estimates of fuel and purchased power costs that are eventually reconciled to actual costs experienced. This PPFAC also provides for a reconciliation between actual and estimated costs of the last three months of estimated costs used in True-Up Component calculations.

PPFAC Year - A consecutive 12-month period beginning each April 1 and lasting through March 31 the following year. The initial term of the PPFAC will begin on the effective date of the Commission decision in this proceeding (Decision No. XXXXX) and end on March 31, 2009. The first full year of the PPFAC will begin on April 1, 2009 and end on March 31, 2010. The first True-Up Component will include costs and revenues from January 1, 2009 through March 31, 2009.

Preference Power - Power allocated to TEP wholesale customers by federal power agencies such as the Western Area Power Administration.

Retail Native Load Energy Sales – The portion of load from Total Native Load Energy Sales retail customers that is served by TEP and located within the TEP control area.

Short Term Sales – Wholesale sales made to non-Native Load customers for the purpose of optimizing the TEP system, using TEP owned or contracted generation and purchased power, less Mark-to-Market Accounting adjustments.

Short Term Sales Revenue - The revenue recorded from wholesale sales made to non-Native Load customers, for the purpose of optimizing the TEP system, using TEP-owned or contracted generation and purchased power, less Mark-to-Market Accounting adjustments.

SO_2 Allowance Sales – The revenues related to the sale of SO_2 emission allowances, including Gain on SO_2 Allowance Sales and Auction Proceeds net of Commissions Paid.

Total Native Load Energy Sales – Retail Native Load Energy Sales and Long Term Energy Sales for which TEP has a generation service obligation.

True-Up Component - An amount expressed as a rate per kWh charge that is updated annually on April 1 of each year and effective with the first billing cycle in April. The purpose of this charge is to provide for a true-up mechanism to reconcile any over or under-recovered amounts from the preceding PPFAC Year tracking account balances to be refunded/collected from customers in the coming year's PPFAC rate. The first True-Up Component will include costs and revenues from January 1, 2009 through March 31, 2009.

True-Up Component Tracking Account - An account that records on a monthly basis the account balance to be collected or refunded via the True-Up Component rate as compared to the actual True-Up Component revenues, plus Applicable Interest; the balance of which at the close of the preceding PPFAC Year is, subject to periodic audit, then reflected in the next True-Up Component calculation. TEP files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Wheeling Costs (FERC Account 565, Transmission of Electricity by Others) - Amounts payable to others for the transmission of TEP's electricity over transmission facilities owned by others.

Wholesale Trading Activity – Revenue recorded from realized wholesale trading profits.

3. PPFAC COMPONENTS

The PPFAC Rate will consist of two components designed to provide for the recovery of actual, prudently incurred fuel and purchased power costs. Those components are:

1. The Forward Component, which recovers or refunds differences between expected PPFAC Year (each April 1 through March 31 period shall constitute a PPFAC Year) fuel and purchased power costs and those embedded in base rates.

2. The True-Up Component, which tracks the differences between the PPFAC Year's actual fuel and purchased power costs and those costs recovered through the combination of base rates and the Forward Component, and which provides for their recovery during the next PPFAC Year.

The PPFAC Year begins on April 1 and ends the following March 31. The first full PPFAC Year in which the PPFAC rate shall apply will begin on April 1, 2009 and end on March 31, 2010. Succeeding PPFAC Years will begin on each April 1 thereafter.

For the period from when the Commission issued Decision No. XXXXX in this case – until March 31, 2009 – the Base Cost of Fuel and Purchased Power rate established in that decision will be in effect. The first True-Up will include costs and revenues from January 1, 2009 through March 31, 2009.

On or before October 31 of each year, TEP will submit a PPFAC Rate filing, which shall include a proposed calculation of the components for the PPFAC rate. This filing shall be accompanied by supporting information as Staff determines to be required. TEP will supplement this filing with a True-Up Component filing on or before February 1 in order to replace estimated balances with actual balances, as explained below.

A. Forward Component Description

The Forward Component is intended to refund or recover the difference between: (1) the fuel and purchased power costs embedded in base rates and (2) the forecasted fuel and purchased power costs over a PPFAC Year that begins on April 1 and ends the following March 31. TEP will submit, on or before October 31 of each year, a forecast for the upcoming PPFAC year (April 1 through March 31) of its fuel and purchase power costs. It will also submit a forecast of kWh sales for the same PPFAC year, and divide the forecasted costs by the forecasted sales to produce the cents per kWh unit rate required to collect those costs over those sales. The result of subtracting the Base Cost of Fuel and Purchased Power from this unit rate shall be the Forward Component.

All revenues from Short Term Sales will be credited against fuel and purchased power costs. Ten percent of the net positive margins realized by TEP during the PPFAC year on its Wholesale Trading Activities will be credited against fuel and purchased power costs. Fifty percent of the margins realized by TEP on SO_2 Allowance Sales will be credited against fuel and purchased power costs.

TEP shall maintain and report monthly the balances in a Forward Component Tracking Account, which will record TEP's over/under-recovery of its actual costs of fuel and purchased power as compared to the actual Base Cost of Fuel and Purchased Power revenue and Forward Component revenue. This Account will operate on a PPFAC Year basis (i.e. April 1 to the following March 31), and its balances will be used to administer this PPFAC's True-Up Component, which is described immediately below.

B. True-Up Component Description

The True-Up Component in any current PPFAC Year is intended to refund or recover the balance accumulated in the Forward Component Tracking Account (described above) during the previous PPFAC year. Also, any remaining balance from the True-Up Component Tracking Account as of March 31 would roll over into the True-Up Component for the coming PPFAC year starting April 1.The sum of projected Forward Component Tracking Account and True-Up Component Tracking Account balances on March 31 is divided by the forecasted PPFAC year kWh sales to determine the True-Up Component for the coming PPFAC year.

TEP shall maintain and report monthly the balances in a True-Up Component Tracking Account, which will reflect monthly collections or refunds under the True-Up Component and the amounts approved for use in calculating the True-Up Component.

Each annual TEP filing on October 31 will include an accumulation of Forward Component Tracking Account balances and True-Up Component Tracking Account balances for the preceding April through September and an estimate of the balances for October through March (the remaining six months of the current PPFAC Year). The TEP filing shall use these balances to calculate a preliminary True-Up Component for the coming PPFAC Year. On or before February 1, TEP will submit a supplemental filing that recalculates the True-Up Component.

This recalculation shall replace estimated monthly balances with those actual monthly balances that have become available since the October 31 filing.

The October 31 filing's use of estimated balances for October through March (with supporting workpapers) is required to allow the PPFAC review process to begin in a way that will support its completion and a Commission decision before April 1. The February 1 updating will allow for the use of the most current balance information available. In addition to the February 1 update filing, TEP's monthly filings (for the months of September through December) of Forward Component Tracking Account balance information and True-Up Component Tracking Account balance information will include a recalculation (replacing estimated balances with actual balances as they become known) of the projected True-Up Component unit rate required for the next PPFAC Year.

The True-Up Component Tracking Account will measure the changes each month in the True-Up Component balance used to establish the current True-Up Component as a result of collections under the True-Up Component in effect. It will subtract each month's True-Up Component collections from the True-Up Component balance. The True-Up Component Account will also include Applicable Interest on any balances. TEP shall file the amounts and supporting calculations and workpapers for this account each month.

4. CALCULATION OF THE PPFAC RATE

The PPFAC rate is the sum of the two components; i.e., Forward Component and True-Up Component. The PPFAC rate shall be applicable to TEP's retail electric rate schedules (except those specifically exempted) and is adjusted annually. The PPFAC Rate shall be applied to the customer's bill as a monthly kilowatt-hour ("kWh") charge that is the same for all customer classes.

The PPFAC rate shall be reset on April 1 of each year, and shall be effective with the first April billing cycle only after approval by the Commission. It is not prorated. The first True-Up Component will include costs and revenues from January 1, 2009 through March 31, 2009.

5. FILING AND PROCEDURAL DEADLINES

A. October 31 Filing

TEP shall file the PPFAC rate with all Component calculations for the PPFAC year beginning on the next April 1, including all supporting data, with the Commission on or before October 31 of each year. That calculation shall use a forecast of kWh sales and of fuel and purchased power costs for the coming PPFAC year, with all inputs and assumptions being the most current available for the Forward Component. The filing will also include the True-Up Component calculation for the year beginning on the next April 1, with all supporting data. That calculation will use the same forecast of sales used for the Forward Component calculation.

B. February 1 Filing

TEP will update the October 31 filing by February 1. This update will replace estimated Forward Component Tracking Account balances, and the True-Up Component Tracking Account balances, with actual balances and with more current estimates for those months (January, February and March) for which actual data are not available. The new PPFAC rate will go into effect on April 1 only after approval by the Commission.

C. Additional Filings

TEP will also file with the Commission any additional information that the Staff determines it requires to verify the component calculations, account balances, and any other matter pertinent to the PPFAC.

D. Review Process

The Commission Staff and interested parties will have an opportunity to review the October 31 and February 1 forecast, balances, and supporting data on which the calculations of the two PPFAC components have been based. Any objections to the October 31 calculations must be filed within 45 days of the TEP filing. Any objections to the February 1 calculations must be filed within 15 days of the TEP filing.

E. Extraordinary Circumstances

Should an unusual event occur that causes a drastic change in forecasted fuel and energy prices – such as a hurricane or other calamity – TEP will have the ability to request an adjustment to the Forward Component reflecting such a change. The Commission may provide for the change over such period as the Commission determines appropriate.

6. VERIFICATION AND AUDIT

The amounts charged through the PPFAC will be subject to periodic audit to assure their completeness and accuracy and to assure that all fuel and purchased power costs were incurred reasonably and prudently. The Commission may, after notice and opportunity for hearing, make such adjustments to existing balances or to already recovered amounts as it finds necessary to correct any accounting or calculation errors or to address any costs found to be unreasonable or imprudent. Such adjustments, with appropriate interest, shall be recovered or refunded in the True-Up Component for the following year (i.e. starting the next April 1.)

7. SCHEDULES

Samples of the following schedules are attached to this Plan of Administration:

Schedule 1	PPFAC Rate Calculation Effective April 1, 20XX
Schedule 2	PPFAC Forward Component Rate Calculation Effective April 1, 20XX
Schedule 3	PPFAC Forward Component Tracking Account (in effect April 1, 20XX – March 31, 20XX)
Schedule 4	PPFAC True-Up Component Rate Calculation Effective Month XX, 20XX
Schedule 5	PPFAC True-Up Component Tracking Account (in effect April 1, 20XX – March 31, 20XX). The first True-Up will include costs and revenues from January 1, 2009 through March 31, 2009.

8. COMPLIANCE REPORTS

TEP shall provide monthly reports to Staff's Compliance Section and to the Residential Utility Consumer Office detailing all calculations related to the PPFAC. A TEP Officer shall certify under oath that all information provided in the reports itemized below is true and accurate to the best of his or her information and belief. These monthly reports shall be due within 30 days of the end of the reporting period.

The publicly available reports will include at a minimum:

1. The PPFAC Rate Calculation (Schedule 1); Forward Component and True-Up Component Calculations (Schedules 2 and 4); Annual Forward Component and, True-Up Component Tracking Account Balances (Schedules 3 and 5). Additional information will provide other relative inputs and outputs such as:
   a. Total power and fuel costs.
   b. Customer sales in both MWh and thousands of dollars by customer class.
   c. Number of customers by customer class.
   d. A detailed listing of all items excluded from the PPFAC calculations.
   e. A detailed listing of any adjustments to the adjustor reports.
   f. Total short term sales revenues.
   g. System losses in MWh.
   h. Monthly maximum retail demand in MW.
   i. SO_2 allowance sales.

2. Identification of a contact person and phone number from TEP for questions.

TEP shall also provide to Commission Staff monthly reports containing the information listed below. These reports shall be due within 30 days of the end of the reporting period. These additional reports may be provided confidentially.

A. Information for each generating unit will include the following items:
   1. Net generation, in MWh per month, and 12 months cumulatively.
   2. Average heat rate, both monthly and 12-month average.
   3. Equivalent forced-outage rate, both monthly and 12-month average.

4. Outage information for each month including, but not limited to, event type, start date and time, end date and time, and a description.
5. Total fuel costs per month.
6. The fuel cost per kWh per month.

B. Information on power purchases will include the following items per seller (information on economy interchange purchases may be aggregated):
1. The quantity purchased in MWh.
2. The demand purchased in MW to the extent specified in the contract.
3. The total cost for demand to the extent specified in the contract.
4. The total cost of energy.

C. Information on short-term sales will include the following items:
1. An itemization of short-term sales margins per buyer.
2. Details on negative short-term sales margins.

D. Fuel purchase information shall include the following items:
1. Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge, usage, surcharges and fuel.
2. Natural gas commodity costs, categorized by short-term purchases (one month or less) and longer term purchases, including price per therm, total cost, supply basin, and volume by contract.

E. TEP will also provide:
1. Monthly projections for the next 12-month period showing estimated (Over)/undercollected amounts.
2. A summary of unplanned outage costs by resource type.
3. The data necessary to arrive at the Native Load Energy Sales MWh reflected in the non-confidential filing.
4. The data necessary to arrive at the Total Fuel and Purchased Power cost reflected in the non-confidential filing (Section 8.1.a).

In addition, TEP will prepare certain schedules and documents that will provide the necessary transparency of TEP's fuel and purchased power procurement activities such that the prudence of these activities can be determined and compliance with company procurement protocols can be confirmed.

Workpapers and other documents that contain proprietary or confidential information will be provided to the Commission Staff under an appropriate protective agreement. TEP will keep fuel and purchased power invoices and contracts available for Commission review. The Commission has the right to review the prudence of fuel and power purchases and any calculations associated with the PPFAC at any time. Any costs flowed through the PPFAC are subject to refund, if those costs are found to be imprudently incurred.

9. ALLOWABLE COSTS

A. Accounts

The allowable PPFAC costs include fuel and purchased power costs incurred to provide service to retail customers. Additionally, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PPFAC. The allowable cost components include the following Federal Energy Regulatory Commission ("FERC") accounts:

- 501 Fuel (Steam)
- 547 Fuel (Other Production)
- 555 Purchased Power
- 565 Wheeling (Transmission of Electricity by Others)

These accounts are subject to change if the Federal Energy Regulatory Commission alters its accounting requirements or definitions.

B. Other Allowable Costs

- None without preapproval from the Commission in an Order.

TUCSON ELECTRIC POWER COMPANY
Schedule 1
Purchased Power and Fuel Adjustment Clause (PPFAC) Rate Calculation Effective April 1, 20XX
(\$/kWh)

Line No.	PPFAC Rate Calculation		Current April 1, 20XX [1]	Proposed April 1, 20XX	Increase / (Decrease) \$.000000/kWh	%
1	Forward Component Rate (Sch. 2, L12)		\$ -	\$ -	\$ -	0.00%
2	True Up Component Rate (Sch. 4, L5)		\$ -	\$ -	\$ -	0.00%
3	PPFAC Rate April 1, 20XX and 20XX	(L1+L2)	\$ -	\$ -	\$ -	0.00%

Notes:
[1] See April 1, 20XX PPFAC Filing.

TUCSON ELECTRIC POWER COMPANY
Schedule 2
PPFAC Forward Component Rate Calculation Effective April 1, 20XX
(Forward Component Rate in $/kWh)

Line No.	PPFAC Forward Component Rate - Calculation	Current April 1, 20XX [1]	Proposed April 1, 20XX	Increase / (Decrease) $ Values	Increase / (Decrease) %
1	Projected PPFAC Fuel and Purchased Power Costs [2]	$ -	$ -	$ -	0.00%
2	Projected Short Term Sales Revenue Credit [2,3]	$ -	$ -	$ -	0.00%
3	Projected Wholesale Trading Activities Credit [4]	$ -	$ -	$ -	0.00%
4	Projected SO2 Allowance Sales Credit [5]	$ -	$ -	$ -	0.00%
5	Net Fuel and Purchased Power Cost (L1+ L2 +L3 +L4)	$ -	$ -	$ -	0.00%
6	Projected Native Load Energy Sales (kWhs)	0	0	0	0.00%
7	Projected Average Net Fuel Costs $/kWh (L5/L6)	$0	$0	$0	0.00%
8	Base Cost of Fuel and Purchased Power $/kWh	$ -	$ -	$ -	0.00%
9	Difference between Projected Cost & Base Cost (L7-L8)	$ -	$ -	$ -	0.00%
10	Forward Component Costs (L6*L9)	$ -	$ -	$ -	0.00%
11	Projected Energy Sales Less Low-Income Customer Sales (kWh)	0	0	0	0.00%
12	Forward Component Rate April 1, 20XX and 20XX $/kWh (L10/ L11)	$ -	$ -	$ -	0.00%

Notes:

[1] See April 1, 20XX PPFAC Filing.

[2] Excludes mark-to-market accounting adjustments.

[3] Short Term Sales revenues are credited at 100% as approved by the Commission in Decision No. xxxxx

[4] 10% of Wholesale Trading Activities credited against Fuel and Purchased Power Costs as approved by the Commission in Decision No. xxxxx

[5] 50% of SO2 Allowance Sales credited against Fuel and Purchased Power Costs as approved by the Commission in Decision No. xxxxx

TUCSON ELECTRIC POWER COMPANY
Schedule 3
Forward Component Tracking Account - (PPFAC Prior Forward Component Rate in effect from Apr 1, 20XX to Mar 31, 20XX
($ in thousands; Forward Component Rate and Base Rate in $/kWh)

Line			Apr-0X	May-0X	Jun-0X	Jul-0X	Aug-0X	Sep-0X	Oct-0X	Nov-0X	Dec-0X	Jan-0X	Feb-0X	Mar-0X	Total
1	Prior Month Balance	(L18)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
	Energy Sales														
2	Retail Native Load Energy Sales (MWh)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.5	Retail Native Load Energy Sales Less Low-Income Sales (MWh)		0	0	0	0	0	0	0	0	0	0	0	0	0
3	Retail Native Load Energy Sales including losses (MWh)[1]		0	0	0	0	0	0	0	0	0	0	0	0	0
4	Long Term Energy Sales (MWh)		0	0	0	0	0	0	0	0	0	0	0	0	0
5	Long Term Energy Sales including losses(MWh)[2]		0	0	0	0	0	0	0	0	0	0	0	0	0
6	Total Native Load Energy Sales (MWh)	(L2 + L4)	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Total Native Load Energy Sales including losses(MWh)	(L3 + L5)	0	0	0	0	0	0	0	0	0	0	0	0	0
	Fuel and Purchased Power Costs														
8	Fuel and Purchased Power Costs[3]		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Short Term Sales Revenue Credit[4]		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Wholesale Trading Activities Credit[5]		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	SO_2 Allowance Sales Credit[6]		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Net Fuel and Purchased Power Costs	(L8-L9-L10-L11)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Base Fuel Rate & Forward Component Recovery														
13	PPFAC Retail Power Supply Costs	(L3 /L7*L12)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
14	Base Rate Power Supply Recovery April 1, 2008 - Mar 31, 2009	(L2 * L19)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Forward Component Recovery[7]	(L2.5 * L20)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	(Over) / Under Collections and Accrued Interest														
16	(Over)/Under Collections	(L13 -L14 - L15)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	Interest[8]	(L16*L21 / 12)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	**Tracking Account Balance**[9]	(L1 + L16 + L17)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

19	Total Base Cost of *Fuel & Purchased Power* - $ per kWh	$0.028896
20	Forward Component Rate - $ per kWh	$0.00000
21	Interest Rate[8]	X.XX%

Notes:

1. Retail energy losses are the difference between billed retail energy sales and TEP's control area metered quantity.
2. Long Term Energy Sales losses calculated using applicable EHV loss percentage as defined in appropriate OATT
3. Includes total native load and short term fuel and purchased power excluding mark-to-market accounting adjustments.
4. Includes Short Term Sales Revenue at 100% per Decision xxxx excluding mark-to-market accounting adjustments.
5. 10% of Wholesale Trading Activities net positive margins realized by TEP during the PPFAC year are credited annually against Fuel and Purchased Power Costs
6. 50% of SO_2 Allowance Sales credited against Fuel and Purchased Power Costs
7. Forward Component Rates $/kWh Effective Apr 1, 20XX to Mar 31, 20XX
8. Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15 on the first business day of the calendar year.
9. Tracking Account Balance Line 18 carried to Schedule 4, Line 1.

Schedule presentation will appear to roundup $'s and MWhs; however calculations are performed on an actual $ and MWh basis with resultant Rates/kWh roundup to $0.000000/kWh

DECISION NO. ______

TUCSON ELECTRIC POWER COMPANY
Schedule 4
PPFAC True Up Component Rate Calculation Effective April 1, 20XX
(True Up Component Rate in $/kWh)

Line No.	PPFAC Historical Component Rate - Calculation	Current April 1, 20XX [1]	Proposed April 1, 20XX	Increase / (Decrease) $ Values	Increase / (Decrease) %
1	Forward Component Tracking Account Balance (From Schedule 3, L18, Cl P) [2,3]	$ -	$ -	$ -	0.00%
2	True Up Component Tracking Account Balance (From Schedule 5, L8) [4]	$ -	$ -	$ -	0.00%
3	Total True Up Amount to be (refunded)/Collected Balance (L1+L2) [5]	$ -	$ -	$ -	
4	Projected Native Load Energy Sales Less Low-Income Customer Sales (kWh)	0	0	-	0.00%
5	Applicable True Up Component Rate for Apr 1, 20XX & 20XX ($/kWh) (L3 / L4)	$ -	$ -	$ -	0.00%

Notes:

[1] See April 1, 20XX PPFAC Filing.

[2] Current Forward Component Tracking Account Balance as of filing

[3] Includes interest for those months that are projected

[4] Because the actual amount of revenue to be received in January, February, & March from application of the prior Applicable True Up Component is not available at the time of the Feb 1st filing, Schedule 5 will reflect estimates for those periods as well as true-up calculations for the prior period estimates, See Schedule 5 for more detail.

[5] Beginning Balance as of April 1, 20XX - to be carried forward to subsequent period PPFAC, True Up Component Tracking account Balance, Schedule 5, L1.

TUCSON ELECTRIC POWER COMPANY
Schedule 5
True Up Component Tracking Account - Prior PPFAC True Up Component Rate in Effect April 1, 20XX through Mar 31, 20XX
($ in thousands; rate in $/kWh)

											20XX data		
Line No.		April	May	June	July	August	September	October	November	December	January	February	March
1a	TU Beginning Balance as of Apr. 1, 20XX [1] and thereafter.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1b	FC tracking Account Balance as of March 31, 20XX	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Revenue True-up from January-March Estimate [2]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	TU Adjusted Beginning Balance (L1 + L2)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Applicable True Up Component Rate ($/kWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Retail Billed Sales Less Low-Income Sales (MWhs) [3]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Less Revenue from Applicable TU (L4 x L5) [4]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Monthly Interest (Line3 * Int Rate/12) [5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	TU Ending Balance; (L3 - L6 + L7)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes:

[1] Beginning Balance as of April 1, 20XX - carried forward April 1, 20XX PPFAC Filing

[2] True-up is the result of using estimated revenue for January through March since the actual amount was not available at the time of prior period PPFAC filing - No true-up since no rate applied in Prior April 20XX Filing.

[3] Sales amounts are for energy billed beginning with the first billing cycle of April 20XX.

[4] Generally, Line 4 x Line 5 = Line 6; however, differences may occur due to billing adjustments.

[5] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15 on the first business day of the calendar year. X.XX%

Schedule presentation will appear to roundup $'s and MWhs; however calculations are performed on an actual $ and MWh basis with resultant Rates/kWh roundup to $0.000000/kWh

Settlement Exhibit No. 7

TUCSON ELECTRIC POWER COMPANY
RATE INCREASE PROPOSAL BY RATE SCHEDULE

Line No.	Pricing Plans	Present and Proposed Rate Schedules	Adjusted TY Revenue (Excludes DSM & Includes CTC)	Proposed Revenue Increase	Total Proposed Revenue Requirement	Percentage Increase by Rate Schedule
			(A)	(B)	(A) + (B)	(B) / (A)
1	*Lifeline*	*R-06 and R-08*	$13,071,130	0	$13,071,130	0.0%
2	Residential Service	R-01	$317,539,032	$19,482,866	$337,021,898	6.1%
3	Residential Water Heating - Frozen	R-02F (FROZEN) (1)	$369,771	$22,688	$392,458	6.1%
4	Residential Time of Use	R-21F (FROZEN) (1)	$3,968,356	$243,482	$4,211,838	6.1%
5	Residential Time of Use	R-70F (FROZEN) (2)	$5,051,329	$309,928	$5,361,257	6.1%
6	Special Residential Electric Service	R-201AF, R-201BF, R-201CF (FROZEN) (2)	$7,837,008	$480,846	$8,317,854	6.1%
7	RESIDENTIAL TOTAL		347,836,625	20,539,810	368,376,435	5.9%
8	General Service	GS-10	$184,988,888	$11,350,144	$196,339,032	6.1%
9	General Service PRS	PRS-10	$27,548	$1,690	$29,239	6.1%
10	General Service Time of Use	GS-76 (FROZEN) (2)	$11,697,293	$717,697	$12,414,990	6.1%
11	Interruptible Agricultural Pumping	GS-31	$823,391	$50,520	$873,911	6.1%
12	General Service Mobile Home Parks	GS-11F (FROZEN) (1)	$5,124,900	$314,442	$5,439,342	6.1%
13	Large General Service	GS-13	$96,038,800	$5,892,539	$101,931,338	6.1%
14	Large General Service PRS	PRS-13	$673,375	$41,315	$714,690	6.1%
15	Large General Service Time of Use	GS-85AF (2) and GS-85F (1) (FROZEN)	$9,028,082	$553,925	$9,582,008	6.1%
15	Large Light and Power	LLP-14	$37,294,915	$2,288,260	$39,583,175	6.1%
16	Large Light and Power PRS	PRS-14	$7,426,586	$455,664	$7,882,251	6.1%
17	Large Light and Power Time of Use	LLP-90AF (2) and LLP 90F (1) (FROZEN)	$14,084,031	$864,137	$14,948,168	6.1%
18	Mines	Contract	$45,544,537	$2,794,422	$48,338,959	6.1%
19	Traffic Signals and Street Lighting	PS-41,P47	$2,267,167	$139,104	$2,406,271	6.1%
20	Lighting	PS-50,GS-51	$2,183,039	$133,942	$2,316,981	6.1%
21	Municipal Service	PS-40	$8,096,168	$496,747	$8,592,915	6.1%
22	Municipal Water Pumping	PS-43	$7,956,899	$488,202	$8,445,101	6.1%
23	TOTAL		$781,092,244	$47,122,562	$828,214,806	6.0%

Notes:
(1) These pricing plans are frozen to existing and new subscription.
(2) These pricing plans are frozen to new subscription only

DECISION NO. ____________

Settlement Exhibit No. 8

Tucson Electric Power
The Energy People

Pricing Plan LLP-90N
Large Light and Power Service Time-of-Use

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

CHARACTER OF SERVICE
Service shall be three phase, 60 Hertz, Primary Service, and shall be supplied directly from any 46,000 volt, or higher voltage, system at a delivery voltage of not less than 13,800 volts and delivered at a single point of delivery unless otherwise specified in the contract.

PRICE SCHEDULE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge — $500.00 per month

Demand Charges (includes Generation Capacity):

Summer On-peak	$20.030 per kW
Summer Off-peak Excess Demand	$10.030 per kW
Winter On-peak	$15.030 per kW
Winter Off-peak Excess Demand	$ 7.530 per kW

Note:
1. For demand billing, "on-peak demand" shall be based on demand measured during both peak and shoulder peak periods.
2. Excess off-peak demand is defined as that positive amount (if any) by which off-peak billing demand exceeds 150% of "on-peak demand" - where "on-peak demand " includes peak and shoulder peak periods.

Energy Charges (excluding Fuel and Purchased Power):

	Summer (May – October)	Winter (November - April)
On-Peak	$0.001113	$0.000723
Shoulder-Peak	$0.001113	N/A
Off-Peak	$0.000716	$0.000521

Fuel and Purchased Power (per kWh):

	Summer (May – October)	Winter (November - April)
On-Peak	$0.041786	$0.027126
Shoulder-Peak	$0.041786	N/A
Off-Peak	$0.026872	$0.019542

Tucson Electric Power
The Energy People

Pricing Plan LLP-90N
Large Light and Power Service Time-of-Use

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

The Summer periods below apply on all days for consumption-based (kWh-based charges) charges.

On-Peak is 2:00 p.m. to 6:00 p.m.
Shoulder-Peak is 12:00 p.m. (noon) to 2:00 p.m. and 6:00 p.m. to 8:00 p.m. (included with On-Peak for demand-based (kW-based) charges).
Off-Peak is 12:00 a.m. (midnight) to 12:00 p.m. (noon) and 8:00 p.m. to 12:00 a.m. (midnight)

The Winter periods below apply on all days for consumption-based (kWh-based charges) charges.

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.
Shoulder-Peak: there are no shoulder peak periods in the winter.
Off-Peak is 12:00 a.m. (midnight) to 6:00 a.m., 10:00 a.m. to 5:00 p.m., and 9:00 p.m. to 12:00 a.m. (midnight)

SHOULDER CONSUMPTION (kWh) IN OCTOBER

Any shoulder consumption (kWh) remaining from October usage shall be billed at the summer shoulder price in following billing months.

BILLING DEMAND

For demand billing, on-peak demand shall be based on demand measured during both peak and shoulder peak periods.

The billing demand shall be specified in the contract, but shall not be less than 3,000 kW. Additionally, the On-Peak billing demand shall not be less than 50.00% of the maximum On-Peak billing demand in the preceding eleven months, unless otherwise specified in the contract.

Excess off-peak demand is defined as that positive amount (if any) by which off-peak billing demand exceeds 150% of on-peak period demand - where "on-peak" includes peak and shoulder peak periods. .

In the event that excess off-peak demand occurs, excess off-peak demand shall be billed at the off-peak excess demand price.

PRIMARY SERVICE

The above rate is subject to Primary Service and Metering. The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers

Tucson Electric Power
The Energy People

Pricing Plan LLP-90N
Large Light and Power Service Time-of-Use

POWER FACTOR ADJUSTMENT

The above rate is subject to a discount or a charge of 1.3¢ per kW of billing demand for each 1% the average monthly power factor is above or below 90% lagging to a maximum discount of 13.0¢ per kW of billing demand per month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:	
Meter Services	$300.00 per month
Meter Reading	$025.00 per month
Billing & Collection	$150.00 per month
Customer Delivery	$ 25.00 per month
Demand Charges ($/kW)	
Generation Capacity Charges (in $/kW)	
Summer On-peak	$13.977 per kW
Summer Off-peak Excess Demand	$ 4.841 per kW
Winter On-peak	$10.058 per kW
Winter Off-peak Excess Demand	$ 3.422 per kW
Fixed Must Run Charges (in $/kW)	
Summer & Winter On-peak	$ 1.728 per kW
Summer & Winter Off-peak Excess Demand	$ 0.864 per kW
Transmission (in $/kW)	
Summer On-peak Demand & Off-peak Excess Demand(kW)	$ 3.374 per kW
Winter On-peak Demand & Off-peak Excess Demand (kW)	$ 2.531 per kW
Transmission - Ancillary Services 1 System Control & Dispatch	
Summer On-peak Demand & Off-peak Excess Demand(kW)	$ 0.046 per kW
Winter On-peak Demand & Off-peak Excess Demand (kW)	$ 0.034 per kW
Transmission - Ancillary Services 2 Reactive Supply and Voltage Control	
Summer On-peak Demand & Off-peak Excess Demand(kW)	$ 0.180 per kW
Winter On-peak Demand & Off-peak Excess Demand (kW)	$ 0.135 per kW

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Pricing Plan LLP-90N
Large Light and Power Service Time-of-Use

Transmission - Ancillary Services 3 Regulation and Frequency Response

Summer On-peak Demand & Off-peak Excess Demand(kW)	$ 0.175 per kW
Winter On-peak Demand & Off-peak Excess Demand (kW)	$ 0.131 per kW

Transmission - Ancillary Services 4 Spinning Reserve Service

Summer On-peak Demand & Off-peak Excess Demand(kW)	$ 0.473 per kW
Winter On-peak Demand & Off-peak Excess Demand (kW)	$ 0.355 per kW

Transmission - Ancillary Services 5 Supplemental Reserve Service

Summer On-peak Demand & Off-peak Excess Demand(kW)	$ 0.077 per kW
Winter On-peak Demand & Off-peak Excess Demand (kW)	$ 0.058 per kW

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Energy Charges ($/kWh):

Delivery Charges (in $/kWh) excluding Systems Benefits Charges: $0.000433 per kWh

	Summer (May – October)	Winter (November - April)
On-Peak	$0.000680	$0.000290
Shoulder-Peak	$0.000680	N/A
Off-Peak	$0.000283	$0.000088

System Benefits Charges (in $/kWh) $0.000433 per kWh

Fuel and Purchased Power Charges (in $/kWh):

	Summer (May – October)	Winter (November - April)
On-Peak	$0.041786	$0.027126
Shoulder-Peak	$0.041786	N/A
Off-Peak	$0.026872	$0.019542

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

Tucson Electric Power
The Energy People

Pricing Plan LLP-90N
Large Light and Power Service Time-of-Use

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added 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 the Company 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.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

Tucson Electric Power
The Energy People

Settlement Exhibit No. 8

Pricing Plan R-70N-B
Residential Time-of-Use – Weekend Includes Shoulder

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service unless otherwise addressed by specific rate schedules, when all energy is supplied at one point of delivery and through one metered service. Not applicable to resale, breakdown, standby, or auxiliary service.
Service under this pricing plan will commence when the appropriate meter has been installed.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

PRICE SCHEDULE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service $ 8.00 per month

Customer Charge, Three Phase service $14.00 per month

Energy Charges:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.079947	$0.050121	$0.041217
Next 3,000 kWh	$0.096571	$0.070121	$0.057841
Over 3,500 kWh	$0.116571	$0.090121	$0.077841

Summer TOU periods:

Weekdays except Memorial Day, Independence Day (July 4), and Labor Day. If Independence Day falls on Saturday, the Weekend schedule applies on the preceeding Friday, July 3. If Independence Day falls on Sunday, the Weekend schedule applies on the following Monday, July 5.

On-Peak: 2:00 p.m. to 6:00 p.m.
Shoulder-Peak 12:00 p.m. (noon) to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.
Off-Peak: 12:00 a.m. (midnight) to 12 p.m (noon) and 8:00 p.m. to 12:00 a.m. (midnight)

Weekends (Saturday and Sunday), Memorial Day, Independence Day (or July 3 or July 5, under above conditions), and Labor Day.

On-Peak: *(There are no On-Peak weekend hours).*
Shoulder-Peak 2:00 p.m. to 8:00 p.m.
Off-Peak 12:00 a.m. (midnight) to 2 p.m. and 8:00 p.m. to 12:00 a.m. (midnight)

Tucson Electric Power
The Energy People

Pricing Plan R-70N-B
Residential Time-of-Use – Weekend Includes Shoulder

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.067066	$0.037066
Next 3,000 kWh	$0.085478	$0.055478
Over 3,500 kWh	$0.105478	$0.075478

Winter TOU periods:

Weekdays except Thanksgiving Day, Christmas Day, and New Years Day. If Christmas Day and New Years Day fall on Saturdays, the Weekend schedule applies on the preceeding Fridays, December 24 and December 31. If Christmas Day and New Years Day fall on Sundays, the Weekend schedule applies on the following Mondays, December 26 and January 2.

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.
Shoulder-Peak: *(There are no Shoulder Peak periods in the winter)*
Off-Peak is 12:00 a.m. (midnight) to 6:00 a.m., 10:00 a.m. to 5:00 p.m., and 9:00 p.m. to 12:00 a.m. (midnight)

Weekends (Saturday and Sunday), Thanksgiving Day, Christmas Day (or December 24 or December 26, under above conditions), and New Years Day (or December 31 or January 2, under above conditions).

On-Peak is 5:00 p.m. to 9:00 p.m.
Shoulder-Peak: *(There are no Shoulder Peak periods in the winter)*
Off-Peak is 12:00 a.m. (midnight) to 5:00 p.m., and 9:00 p.m. to 12:00 a.m. (midnight)

Calculation of Tiered (Block) Usage by TOU Period:

Step 1: Calculate percent usage by TOU period.
Step 2: Calculate the kWh usage by tier (block).
Step 3: Multiply percent usage by TOU period by kWh usage by tier to obtain tiered usage by TOU period.
Example: A customer using 2,000 kWh in a month, with 20% peak usage, 25% shoulder usage, and 55% off-peak usage will have 100 kWh in peak 1st tier, 300 kWh in peak 2nd tier, 125 kWh in shoulder 1st tier, 375 kWh in shoulder 2nd tier, 275 kWh in off-peak 1st tier, and 825 kWh in off-peak 2nd tier.

Fuel and Purchased Power - Base cost (per kWh):

Summer On-Peak	$0.055440
Summer Shoulder-Peak	$0.034876
Summer Off-Peak	$0.019865
Winter On-Peak	$0.042874
Winter Off-Peak	$0.025086

Tucson Electric Power
The Energy People

Pricing Plan R-70N-B
Residential Time-of-Use – Weekend Includes Shoulder

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$1.51 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.29 per month
Customer Delivery	$2.40 per month

Note: Additional meter service charge of $6.00 per month for Three Phase Service.

Energy Charges:

Delivery:
((NOTE: While some delivery charges are negative, the minimum total monthly bill (excluding services provided by third-party service providers), shall be zero. Negative charges reduce the total monthly bill, but are not permitted to create a negative bill, which would result the customer being paid (rather than paying) for TEP services.):

DELIVERY SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.010526	($0.000900)	($0.001396)
Next 3,000 kWh	$0.027150	$0.019100	$0.015228
Over 3,500 kWh	$0.047150	$0.039100	$0.035228

DELIVERY WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.009623	($0.003317)
Next 3,000 kWh	$0.028035	$0.015095
Over 3,500 kWh	$0.048035	$0.035095

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003849 per kWh
System Benefits	$0.000468 per kWh
Transmission	$0.007525 per kWh
Transmission / Ancillary Services	
System Control & Dispatch	$0.000102 per kWh
Reactive Supply and Voltage Control	$0.000402 per kWh
Regulation and Frequency Response	$0.000389 per kWh
Spinning Reserve Service	$0.001055 per kWh
Supplemental Reserve Service	$0.000172 per kWh

Tucson Electric Power
The Energy People

Pricing Plan R-70N-B
Residential Time-of-Use – Weekend Includes Shoulder

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity (per kWh):

Summer On-Peak	$0.055459
Summer Shoulder-Peak	$0.037059
Summer Off-Peak	$0.028651
Winter On-Peak	$0.043481
Winter Off-Peak	$0.026421

Fuel and Purchased Power - Base cost (per kWh):

Summer On-Peak	$0.055440
Summer Shoulder-Peak	$0.034876
Summer Off-Peak	$0.019865
Winter On-Peak	$0.042874
Winter Off-Peak	$0.025086

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added 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 the Company 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.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

Tucson Electric Power
The Energy People

Pricing Plan R-70N-B
Residential Time-of-Use – Weekend Includes Shoulder

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

Settlement Exhibit No. 8

Tucson Electric Power
The Energy People

Pricing Plan R-201BN
Special Residential Electric Service

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To single phase (subject to availability at point of delivery) electric service in individual residences as described in current program details when all service is supplied at one point of delivery and energy is metered through one meter. Additionally, this Schedule requires that the customer use exclusively the Company's service for all space heating and all water heating energy requirements except as provided below and that the customer's home conform to the standards of the Heating, Cooling and Comfort Guarantee program as in effect at the time of subscription to this Schedule. Notwithstanding the above, the customer's use of solar energy for any purpose shall not preclude subscription to this pricing plan.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

Customers must stay on pricing plan R-201BF for a minimum period of one (1) year. A Customer, at his/her discretion and after being served for a twelve (12) month period of this pricing plan, may opt to switch service to the non-time-of-use R-201 pricing plan of R-201AN. The Company shall refund to the Customer any excess moneys paid in total over the entire twelve months under pricing plan R201BF, that would not have been paid under pricing plan R-201AN. A Customer shall be eligible to receive such a refund of excess moneys on a single occasion only.

CHARACTER OF SERVICE
Single phase, 60 Hertz, nominal 120/240 volts.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service $ 8.00 per month

Customer Charge, Three Phase service $14.00 per month

Energy Charges:

Delivery Charges

Mid-Summer (June – August)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.110962	$0.043962	$0.020362
Next 3,000 kWh	$0.130962	$0.063962	$0040362
Over 3,500 kWh	$0.150962	$0.083962	$0.060362

Delivery Charges

Remaining Summer			

Tucson Electric Power
The Energy People

Pricing Plan R-201BN
Special Residential Electric Service

(May, September – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.047962	$0.024162	$0.016462
Next 3,000 kWh	$0.067962	$0.044162	$0.036462
Over 3,500 kWh	$0.087962	$0.064162	$0.056462

Mid-Summer and Remaining Summer TOU periods:

Weekdays except Memorial Day, Independence Day (July 4), and Labor Day. If Independence Day falls on Saturday, the Weekend schedule applies on the preceeding Friday, July 3. If Independence Day falls on Sunday, the Weekend schedule applies on the following Monday, July 5.

On-Peak: 2:00 p.m. to 6:00 p.m.
Shoulder-Peak 12:00 p.m. (noon) to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.
Off-Peak: 12:00 a.m. (midnight) to 12 p.m (noon) and 8:00 p.m. to 12:00 a.m. (midnight)

Weekends (Saturday and Sunday), Memorial Day, Independence Day (or July 3 or July 5, under above conditions), and Labor Day.

On-Peak: *(There are no On-Peak weekend hours)*
Shoulder-Peak *(There are no Shoulder-Peak weekend hours)*
Off-Peak All hours.

Delivery Charges

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.047962	$0.016462
Next 3,000 kWh	$0.067962	$0.036462
Over 3,500 kWh	$0.087962	$0.056462

Winter TOU periods:

Weekdays except Thanksgiving Day, Christmas Day, and New Years Day. If Christmas Day and New Years Day fall on Saturdays, the Weekend schedule applies on the preceeding Fridays, December 24 and December 31. If Christmas Day and New Years Day fall on Sundays, the Weekend schedule applies on the following Mondays, December 26 and January 2.

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.
Shoulder-Peak: there are no shoulder peak periods in the winter.
Off-Peak is 12:00 a.m. (midnight) to 6:00 a.m., 10:00 a.m. to 5:00 p.m., and 9:00 p.m. to 12:00 a.m. (midnight)

Weekends (Saturday and Sunday), Thanksgiving Day, Christmas Day (or December 24 or December 26, under above conditions), and New Years Day (or December 31 or January 2, under above conditions).

On-Peak: *(There are no On-Peak weekend hours)*
Shoulder-Peak *(There are no Shoulder-Peak weekend hours)*
Off-Peak All hours.

Fuel and Purchased Power - Base cost (per kWh):
Mid-Summer On-Peak $0.077356

Tucson Electric Power
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Special Residential Electric Service

Mid-Summer Shoulder-Peak	$0.038166
Mid-Summer Off-Peak	$0.033166
Remaining Summer On-Peak	$0.057356
Remaining Summer Shoulder-Peak	$0.018166
Remaining SummerOff-Peak	$0.013166
Winter On-Peak	$0.061223
Winter Off-Peak	$0.017033

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$1.51 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.29 per month
Customer Delivery	$2.40 per month

Note: Additional meter service charge of $6.00 per month for Three Phase Service.

Energy Charges:

Delivery:

((NOTE: While some delivery charges are negative, the minimum total monthly bill (excluding services provided by third-party service providers), shall be zero. Negative charges reduce the total monthly bill, but are not permitted to create a negative bill, which would result the customer being paid (rather than paying) for TEP services.):

Delivery Mid-Summer (June – August)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.037000	$0.012000	$0.000400
Next 3,000 kWh	$0.057000	$0.032000	$0.020400
Over 3,500 kWh	$0.077000	$0.052000	$0.040400

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Delivery Remaining Summer (May, September – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.010000	$0.003000	$0.000100
Next 3,000 kWh	$0.030000	$0.023000	$0.020100
Over 3,500 kWh	$0.050000	$0.043000	$0.040100

Delivery Winter (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.010000	$0.000100
Next 3,000 kWh	$0.030000	$0.020100
Over 3,500 kWh	$0.050000	$0.040100

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003849 per kWh
System Benefits	$0.000468 per kWh
Transmission	$0.007525 per kWh
Transmission / Ancillary Services	
System Control & Dispatch	$0.000102 per kWh
Reactive Supply and Voltage Control	$0.000402 per kWh
Regulation and Frequency Response	$0.000389 per kWh
Spinning Reserve Service	$0.001055 per kWh
Supplemental Reserve Service	$0.000172 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity (per kWh):

Mid-Summer On-Peak	$0.060000
Mid-Summer Shoulder-Peak	$0.018000
Mid-Summer Off-Peak	$0.006000
Remaining Summer On-Peak	$0.024000
Remaining Summer Shoulder-Peak	$0.007200
Remaining SummerOff-Peak	$0.002400
Winter On-Peak	$0.024000
Winter Off-Peak	$0.002400

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Pricing Plan R-201BN
Special Residential Electric Service

Fuel and Purchased Power - Base cost (per kWh):

Mid-Summer On-Peak	$0.077356
Mid-Summer Shoulder-Peak	$0.038166
Mid-Summer Off-Peak	$0.033166
Remaining Summer On-Peak	$0.057356
Remaining Summer Shoulder-Peak	$0.018166
Remaining SummerOff-Peak	$0.013166
Winter On-Peak	$0.061223
Winter Off-Peak	$0.017033

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added 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 the Company 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.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

Tucson Electric Power

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Pricing Plan R-201AN
Special Residential Electric Service

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To single phase or three phase (Option A only) (subject to availability at point of delivery) electric service in individual residences as described in current program details when all service is supplied at one point of delivery and energy is metered through one meter. Additionally, this Schedule requires that the customer use exclusively the Company's service for all space heating and all water heating energy requirements except as provided below and that the customer's home conform to the standards of the Heating, Cooling and Comfort Guarantee program as in effect at the time of subscription to this Schedule. Notwithstanding the above, the customer's use of solar energy for any purpose shall not preclude subscription to this pricing plan.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

CHARACTER OF SERVICE
Single, 60 Hertz, nominal 120/240 volts.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service	$ 7.00 per month
Customer Charge, Three Phase service	$14.00 per month

Energy Charges:

Delivery Charges

	Mid-Summer (June – August)	Remaining Summer (May, September – October)	Winter (November - April)
First 500 kWh	$0.065598	$0.022737	$0.020737
Next 3,000 kWh	$0.085598	$0.042737	$0.040737
Over 3,500 kWh	$0.105598	$0.062737	$0.060737

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Pricing Plan R-201AN
Special Residential Electric Service

Fuel and Purchased Power - Base cost (per kWh)

Mid-Summer	$0.043166
Remaining-Summer	$0.023166
Winter	$0.027033

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$1.510 per month
Meter Reading	$0.800 per month
Billing & Collection	$3.290 per month
Customer Delivery	$1.400 per month

Note: Additional meter service charge of $6.000 per month for Three Phase Service.

Energy Charges

Delivery Charges
((NOTE: While some delivery charges are negative, the minimum total monthly bill (excluding services provided by third-party service providers), shall be zero. Negative charges reduce the total monthly bill, but are not permitted to create a negative bill, which would result the customer being paid (rather than paying) for TEP services.):

	Mid-Summer (June – August)	Remaining Summer (May, September – October)	Winter (November - April)
First 500 kWh	$0.008275	$0.006275	$0.004275
Next 3,000 kWh	$0.028275	$0.026275	$0.024275
Over 3,500 kWh	$0.048275	$0.046275	$0.044275

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003849 per kWh
System Benefits	$0.000468 per kWh
Transmission	$0.007525 per kWh
Transmission / Ancillary Services	
System Control & Dispatch	$0.000102 per kWh
Reactive Supply and Voltage Control	$0.000402 per kWh
Regulation and Frequency Response	$0.000389 per kWh
Spinning Reserve Service	$0.001055 per kWh
Supplemental Reserve Service	$0.000172 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Tucson Electric Power
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Pricing Plan R-201AN
Special Residential Electric Service

Generation Charges:

Generation Capacity (per kWh):	
Mid-Summer	$0.043361
Remaining-Summer	$0.002500
Winter	$0.002500
Fuel and Purchased Power - Base cost (per kWh):	
Mid-Summer	$0.043166
Remaining-Summer	$0.023166
Winter	$0.027033

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added 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 the Company 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.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

Tucson Electric Power
The Energy People

Settlement Exhibit No. 8

Pricing Plan R-70N-C
Residential Time-of-Use – Weekend Includes Super-Peak

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service unless otherwise addressed by specific rate schedules, when all energy is supplied at one point of delivery and through one metered service. Not applicable to resale, breakdown, standby, or auxiliary service.
Service under this pricing plan will commence when the appropriate meter has been installed.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

PRICE SCHEDULE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service	$ 8.00 per month
Customer Charge, Three Phase service	$14.00 per month

Energy Charges:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.077356	$0.049507	$0.038229
Next 3,000 kWh	$0.096354	$0.069507	$0.057227
Over 3,500 kWh	$0.116354	$0.089507	$0.077227

Summer TOU periods:

Weekdays except Memorial Day, Independence Day (July 4), and Labor Day. If Independence Day falls on Saturday, the Weekend schedule applies on the preceeding Friday, July 3. If Independence Day falls on Sunday, the Weekend schedule applies on the following Monday, July 5.

On-Peak: 2:00 p.m. to 6:00 p.m.
Shoulder-Peak 12:00 p.m. (noon) to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.
Off-Peak: 12:00 a.m. (midnight) to 12 p.m (noon) and 8:00 p.m. to 12:00 a.m. (midnight)

Weekends (Saturday and Sunday), Memorial Day, Independence Day (or July 3 or July 5, under above conditions), and Labor Day.

On-Peak: 2:00 p.m. to 6:00 p.m.
Shoulder-Peak *(There are no Shoulder-peak weekend hours)*
Off-Peak 12:00 a.m. (midnight) to 2 p.m. and 6:00 p.m. to 12:00 a.m. (midnight)

Tucson Electric Power
The Energy People

Pricing Plan R-70N-C
Residential Time-of-Use – Weekend Includes Super-Peak

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.066452	$0.036452
Next 3,000 kWh	$0.084864	$0.054864
Over 3,500 kWh	$0.104864	$0.074864

Winter TOU periods:

Weekdays except Thanksgiving Day, Christmas Day, and New Years Day. If Christmas Day and New Years Day fall on Saturdays, the Weekend schedule applies on the preceeding Fridays, December 24 and December 31. If Christmas Day and New Years Day fall on Sundays, the Weekend schedule applies on the following Mondays, December 26 and January 2.

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.
Shoulder-Peak: *(There are no Shoulder Peak periods in the winter)*
Off-Peak is 12:00 a.m. (midnight) to 6:00 a.m., 10:00 a.m. to 5:00 p.m., and 9:00 p.m. to 12:00 a.m. (midnight)

Weekends (Saturday and Sunday), Thanksgiving Day, Christmas Day (or December 24 or December 26, under above conditions), and New Years Day (or December 31 or January 2, under above conditions).

On-Peak is 5:00 p.m. to 9:00 p.m.
Shoulder-Peak: *(There are no Shoulder Peak periods in the winter)*
Off-Peak is 12:00 a.m. (midnight) to 5:00 p.m., and 9:00 p.m. to 12:00 a.m. (midnight)

Fuel and Purchased Power - Base cost (per kWh):

Summer On-Peak	$0.054330
Summer Shoulder-Peak	$0.034177
Summer Off-Peak	$0.019467
Winter On-Peak	$0.042015
Winter Off-Peak	$0.024584

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

Tucson Electric Power
The Energy People

Pricing Plan R-70N-C
Residential Time-of-Use – Weekend Includes Super-Peak

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$1.51 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.29 per month
Customer Delivery	$2.40 per month

Note: Additional meter service charge of $6.00 per month for Three Phase Service.

Energy Charges:

Delivery:
((NOTE: While some delivery charges are negative, the minimum total monthly bill (excluding services provided by third-party service providers), shall be zero. Negative charges reduce the total monthly bill, but are not permitted to create a negative bill, which would result the customer being paid (rather than paying) for TEP services.):

DELIVERY SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.009938	($0.001547)	($0.001917)
Next 3,000 kWh	$0.028936	$0.018453	$0.017081
Over 3,500 kWh	$0.048936	$0.038453	$0.037081

DELIVERY WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.008866	($0.003779)
Next 3,000 kWh	$0.027278	$0.014633
Over 3,500 kWh	$0.047278	$0.034633

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003849 per kWh
System Benefits	$0.000468 per kWh
Transmission	$0.007525 per kWh

Transmission / Ancillary Services

System Control & Dispatch	$0.000102 per kWh
Reactive Supply and Voltage Control	$0.000402 per kWh
Regulation and Frequency Response	$0.000389 per kWh
Spinning Reserve Service	$0.001055 per kWh
Supplemental Reserve Service	$0.000172 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Tucson Electric Power
The Energy People

Pricing Plan R-70N-C
Residential Time-of-Use – Weekend Includes Super-Peak

Generation Charges:

Generation Capacity (per kWh):

Summer On-Peak	$0.053456
Summer Shoulder-Peak	$0.037092
Summer Off-Peak	$0.026184
Winter On-Peak	$0.043624
Winter Off-Peak	$0.026269

Fuel and Purchased Power - Base cost (per kWh):

Summer On-Peak	$0.054330
Summer Shoulder-Peak	$0.034177
Summer Off-Peak	$0.019467
Winter On-Peak	$0.042015
Winter Off-Peak	$0.024584

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added 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 the Company 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.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

Tucson Electric Power
The Energy People

Pricing Plan R-70N-C
Residential Time-of-Use – Weekend Includes Super-Peak

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

Tucson Electric Power
The Energy People

Pricing Plan R-01
Residential Electric Service

AVAILABILITY
Throughout the entire area where facilities of the Company are of adequate capacity and are adjacent to the premise.

APPLICABILITY
To all single phase or three phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter; however, electric water heating may be metered separately.

Not applicable to resale, breakdown, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, nominal 120/240 volts.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service	$ 7.00 per month
Customer Charge, Three Phase service	$13.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

Delivery Charges

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.046925	$0.047309
Next 3,000 kWh	$0.068960	$0.067309
3,501 kWh and above	$0.088960	$0.087309

Fuel and Purchased Power:

Summer, all kWhs	$0.033198 per kWh
Winter, all kWhs	$0.025698 per kWh

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment in accordance with Rider-1 PPFAC to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

Tucson Electric Power
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Pricing Plan R-01
Residential Electric Service

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$1.51 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.29 per month
Customer Delivery	$1.40 per month

Note: Additional meter service charge of $6.00 per month for Three Phase Service.

Energy Charges (kWh):

Delivery Charges

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.000025	$0.003076
Next 3,000 kWh	$0.022060	$0.023076
3,501 kWh and above	$0.042060	$0.043076

Generation Capacity

Summer	$0.032938 per kWh
Winter	$0.030271 per kWh

Fixed Must-Run	$0.003849 per kWh
System Benefits	$0.000468 per kWh
Transmission	$0.007525 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000102 per kWh
Reactive Supply and Voltage Control	$0.000402 per kWh
Regulation and Frequency Response	$0.000389 per kWh
Spinning Reserve Service	$0.001055 per kWh
Supplemental Reserve Service	$0.000172 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Fuel and Purchased Power:

Summer	$0.033198 per kWh
Winter	$0.025698 per kWh

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

Tucson Electric Power
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Pricing Plan R-01
Residential Electric Service

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added 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 the Company 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.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

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Pricing Plan R-70N-D
Residential Time-of-Use – Weekend Entirely Off-Peak

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service unless otherwise addressed by specific rate schedules, when all energy is supplied at one point of delivery and through one metered service. Not applicable to resale, breakdown, standby, or auxiliary service.
Service under this pricing plan will commence when the appropriate meter has been installed.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

PRICE SCHEDULE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service — $ 8.00 per month

Customer Charge, Three Phase service — $14.00 per month

Energy Charges:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.091873	$0.049814	$0.042073
Next 3,000 kWh	$0.107334	$0.069814	$0.057534
Over 3,500 kWh	$0.127334	$0.089814	$0.077534

Summer TOU periods:

Weekdays except Memorial Day, Independence Day (July 4), and Labor Day. If Independence Day falls on Saturday, the Weekend schedule applies on the preceeding Friday, July 3. If Independence Day falls on Sunday, the Weekend schedule applies on the following Monday, July 5.

On-Peak: 2:00 p.m. to 6:00 p.m.
Shoulder-Peak 12:00 p.m. (noon) to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.
Off-Peak: 12:00 a.m. (midnight) to 12 p.m (noon) and 8:00 p.m. to 12:00 a.m. (midnight)

Weekends (Saturday and Sunday), Memorial Day, Independence Day (or July 3 or July 5, under above conditions), and Labor Day.

On-Peak: *(There are no On-Peak weekend hours)*
Shoulder-Peak *(There are no Shoulder-Peak weekend hours)*
Off-Peak All hours.

Tucson Electric Power
The Energy People

Pricing Plan R-70N-D
Residential Time-of-Use – Weekend Entirely Off-Peak

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.068737	$0.038737
Next 3,000 kWh	$0.085171	$0.055171
Over 3,500 kWh	$0.105171	$0.075171

Winter TOU periods:

Weekdays except Thanksgiving Day, Christmas Day, and New Years Day. If Christmas Day and New Years Day fall on Saturdays, the Weekend schedule applies on the preceeding Fridays, December 24 and December 31. If Christmas Day and New Years Day fall on Sundays, the Weekend schedule applies on the following Mondays, December 26 and January 2.

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.
Shoulder-Peak: there are no shoulder peak periods in the winter.
Off-Peak is 12:00 a.m. (midnight) to 6:00 a.m., 10:00 a.m. to 5:00 p.m., and 9:00 p.m. to 12:00 a.m. (midnight)

Weekends (Saturday and Sunday), Thanksgiving Day, Christmas Day (or December 24 or December 26, under above conditions), and New Years Day (or December 31 or January 2, under above conditions).

On-Peak:	*(There are no On-Peak weekend hours)*
Shoulder-Peak	*(There are no Shoulder-Peak weekend hours)*
Off-Peak	All hours.

Fuel and Purchased Power - Base cost (per kWh):

Summer On-Peak	$0.058271
Summer Shoulder-Peak	$0.036656
Summer Off-Peak	$0.020880
Winter On-Peak	$0.045063
Winter Off-Peak	$0.026368

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

Tucson Electric Power
The Energy People

Pricing Plan R-70N-D
Residential Time-of-Use – Weekend Entirely Off-Peak

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$1.51 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.29 per month
Customer Delivery	$2.40 per month

Note: Additional meter service charge of $6.00 per month for Three Phase Service.

Energy Charges:

Delivery:
((NOTE: While some delivery charges are negative, the minimum total monthly bill (excluding services provided by third-party service providers), shall be zero. Negative charges reduce the total monthly bill, but are not permitted to create a negative bill, which would result the customer being paid (rather than paying) for TEP services.):

DELIVERY SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.022190	($0.000534)	($0.001075)
Next 3,000 kWh	$0.037651	$0.019466	$0.014386
Over 3,500 kWh	$0.057651	$0.039466	$0.034386

DELIVERY WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.010124	($0.002989)
Next 3,000 kWh	$0.026558	$0.013445
Over 3,500 kWh	$0.046558	$0.033445

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003849 per kWh
System Benefits	$0.000468 per kWh
Transmission	$0.007525 per kWh

Transmission / Ancillary Services

System Control & Dispatch	$0.000102 per kWh
Reactive Supply and Voltage Control	$0.000402 per kWh
Regulation and Frequency Response	$0.000389 per kWh
Spinning Reserve Service	$0.001055 per kWh
Supplemental Reserve Service	$0.000172 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Tucson Electric Power
The Energy People

Pricing Plan R-70N-D
Residential Time-of-Use – Weekend Entirely Off-Peak

Generation Charges:

Generation Capacity (per kWh):

Summer On-Peak	$0.055721
Summer Shoulder-Peak	$0.036386
Summer Off-Peak	$0.029186
Winter On-Peak	$0.044651
Winter Off-Peak	$0.027764

Fuel and Purchased Power - Base cost (per kWh):

Summer On-Peak	$0.058271
Summer Shoulder-Peak	$0.036656
Summer Off-Peak	$0.020880
Winter On-Peak	$0.045063
Winter Off-Peak	$0.026368

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added 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 the Company 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.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

Pricing Plan R-70N-D
Residential Time-of-Use – Weekend Entirely Off-Peak

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

Settlement Exhibit No. 8

Tucson Electric Power
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Pricing Plan R-201CN
Special Residential Electric Service

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To single phase (subject to availability at point of delivery) electric service in individual residences as described in current program details when all service is supplied at one point of delivery and energy is metered through one meter. Additionally, this Schedule requires that the customer use exclusively the Company's service for all space heating and all water heating energy requirements except as provided below and that the customer's home conform to the standards of the Heating, Cooling and Comfort Guarantee program as in effect at the time of subscription to this Schedule. Notwithstanding the above, the customer's use of solar energy for any purpose shall not preclude subscription to this pricing plan.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

Customers must stay on pricing plan R-201CF for a minimum period of one (1) year. A Customer, at his/her discretion and after being served for a twelve (12) month period of this pricing plan, may opt to switch service to the non-time-of-use R-201 pricing plan of R-201AN. The Company shall refund to the Customer any excess moneys paid in total over the entire twelve months under pricing plan R201CF, that would not have been paid under pricing plan R-201AN. A Customer shall be eligible to receive such a refund of excess moneys on a single occasion only.

CHARACTER OF SERVICE
Single phase, 60 Hertz, nominal 120/240 volts.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service $ 8.00 per month

Customer Charge, Three Phase service $14.00 per month

Energy Charges:

Delivery Charges

Mid-Summer (June – August)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.099462	$0.040512	$0.019626
Next 3,000 kWh	$0.117162	$0.058212	$0.037326
Over 3,500 kWh	$0.134862	$0.075912	$0.055026

Delivery Charges

Tucson Electric Power
The Energy People

Pricing Plan R-201CN
Special Residential Electric Service

Remaining Summer (May, September – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.044052	$0.022989	$0.016175
Next 3,000 kWh	$0.061752	$0.040689	$0.033875
Over 3,500 kWh	$0.079452	$0.058389	$0.051575

Mid-Summer and Remaining Summer TOU periods:

Weekdays except Memorial Day, Independence Day (July 4), and Labor Day. If Independence Day falls on Saturday, the Weekend schedule applies on the preceeding Friday, July 3. If Independence Day falls on Sunday, the Weekend schedule applies on the following Monday, July 5.

On-Peak: 2:00 p.m. to 6:00 p.m.
Shoulder-Peak 12:00 p.m. (noon) to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.
Off-Peak: 12:00 a.m. (midnight) to 12 p.m (noon) and 8:00 p.m. to 12:00 a.m. (midnight)

Weekends (Saturday and Sunday), Memorial Day, Independence Day (or July 3 or July 5, under above conditions), and Labor Day.

On-Peak: *(There are no On-Peak weekend hours)*
Shoulder-Peak *(There are no Shoulder-Peak weekend hours)*
Off-Peak All hours.

Delivery Charges

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.044052	$0.016175
Next 3,000 kWh	$0.061752	$0.033875
Over 3,500 kWh	$0.079452	$0.051575

Winter TOU periods:

Weekdays except Thanksgiving Day, Christmas Day, and New Years Day. If Christmas Day and New Years Day fall on Saturdays, the Weekend schedule applies on the preceeding Fridays, December 24 and December 31. If Christmas Day and New Years Day fall on Sundays, the Weekend schedule applies on the following Mondays, December 26 and January 2.

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.
Shoulder-Peak: there are no shoulder peak periods in the winter.
Off-Peak is 12:00 a.m. (midnight) to 6:00 a.m., 10:00 a.m. to 5:00 p.m., and 9:00 p.m. to 12:00 a.m. (midnight)

Weekends (Saturday and Sunday), Thanksgiving Day, Christmas Day (or December 24 or December 26, under above conditions), and New Years Day (or December 31 or January 2, under above conditions).

On-Peak: *(There are no On-Peak weekend hours)*
Shoulder-Peak *(There are no Shoulder-Peak weekend hours)*
Off-Peak All hours.

Fuel and Purchased Power - Base cost (per kWh):

Tucson Electric Power
The Energy People

Pricing Plan R-201CN
Special Residential Electric Service

Mid-Summer On-Peak	$0.078903
Mid-Summer Shoulder-Peak	$0.038929
Mid-Summer Off-Peak	$0.033829
Remaining Summer On-Peak	$0.058503
Remaining Summer Shoulder-Peak	$0.018529
Remaining SummerOff-Peak	$0.013429
Winter On-Peak	$0.062447
Winter Off-Peak	$0.017374

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$1.51 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.29 per month
Customer Delivery	$2.40 per month

Note: Additional meter service charge of $6.00 per month for Three Phase Service.

Energy Charges:

Delivery:
((NOTE: While some delivery charges are negative, the minimum total monthly bill (excluding services provided by third-party service providers), shall be zero. Negative charges reduce the total monthly bill, but are not permitted to create a negative bill, which would result the customer being paid (rather than paying) for TEP services.):

Delivery Mid-Summer (June – August)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.032400	$0.010620	$0.000354
Next 3,000 kWh	$0.050100	$0.028320	$0.018054
Over 3,500 kWh	$0.067800	$0.046020	$0.035754

Tucson Electric Power
The Energy People

Pricing Plan R-201CN
Special Residential Electric Service

Remaining Summer (May, September – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.008850	$0.002655	$0.000089
Next 3,000 kWh	$0.026550	$0.020355	$0.017789
Over 3,500 kWh	$0.044250	$0.038055	$0.035489

Delivery Winter (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.008850	$0.000089
Next 3,000 kWh	$0.026550	$0.017789
Over 3,500 kWh	$0.044250	$0.035489

Fixed Must-Run (See Must-Run Generation – Rider No. 2) $0.003849 per kWh
System Benefits $0.000468 per kWh

Transmission $0.007525 per kWh
Transmission / Ancillary Services
System Control & Dispatch $0.000102 per kWh
Reactive Supply and Voltage Control $0.000402 per kWh
Regulation and Frequency Response $0.000389 per kWh
Spinning Reserve Service $0.001055 per kWh
Supplemental Reserve Service $0.000172 per kWh
Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:
Generation Capacity (per kWh):
Mid-Summer On-Peak $0.053100
Mid-Summer Shoulder-Peak $0.015930
Mid-Summer Off-Peak $0.005310

Remaining Summer On-Peak $0.021240
Remaining Summer Shoulder-Peak $0.006372
Remaining SummerOff-Peak $0.002124

Winter On-Peak $0.021240
Winter Off-Peak $0.002124

Pricing Plan R-201CN
Special Residential Electric Service

Fuel and Purchased Power - Base cost (per kWh):

Mid-Summer On-Peak	$0.078903
Mid-Summer Shoulder-Peak	$0.038929
Mid-Summer Off-Peak	$0.033829
Remaining Summer On-Peak	$0.058503
Remaining Summer Shoulder-Peak	$0.018529
Remaining SummerOff-Peak	$0.013429
Winter On-Peak	$0.062447
Winter Off-Peak	$0.017374

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added 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 the Company 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.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

Tucson Electric Power
The Energy People

Pricing Plan LLP-14
Large Light and Power Service

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

CHARACTER OF SERVICE

Service shall be three phase, 60 Hertz, Primary Service, and shall be supplied directly from any 46,000 volt, or higher voltage, system at a delivery voltage of not less than 13,000 volts and delivered at a single point of delivery unless otherwise specified in the contract.

PRICE SCHEDULE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge	\$500.00 per month
Demand Charge (Includes Generation Capacity):	\$16.155 per kW of Billing Demand per month
Energy Charges:	
Energy Charge (excluding Fuel & Purchase Power:	\$0.000433 per kWh
Fuel & Purchase Power	
Summer, all kWhs	\$0.032577 per kWh
Winter, all kWhs	\$0.025077 per kWh

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

BILLING DEMAND
The billing demand shall be specified in the contract, but shall not be less than 3,000 kW. Additionally, the On-Peak billing demand shall not be less than 66.7% of the maximum On-Peak billing demand in the preceding eleven (11) months, unless otherwise specified in the contract.

PRIMARY SERVICE
The above rate is subject to Primary Service and Metering. The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers

POWER FACTOR ADJUSTMENT
The above rate is subject to a discount or a charge of 1.3¢ per kW of billing demand for each 1% the average monthly power factor is above or below 90% lagging to a maximum discount of 13.0¢ per kW of billing demand per month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Tucson Electric Power
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Pricing Plan LLP-14
Large Light and Power Service

Customer Charges:	
Meter Services	$300.00 per month
Meter Reading	$025.00 per month
Billing & Collection	$150.00 per month
Customer Delivery	$025.00 per month
Demand Charges:	
Generation Capacity	$10.898 per kW per month
Fixed Must-Run	$01.582 per kW per month
Transmission	$02.868 per kW per month
Transmission Ancillary Services	
System Control & Dispatch	$0.039 per kW per month
Reactive Supply and Voltage Control	$0.153 per kW per month
Regulation and Frequency Response	$0.148 per kW per month
Spinning Reserve Service	$0.402 per kW per month
Supplemental Reserve Service	$0.065 per kW per month
Energy Imbalance Service: currently charged pursuant to the Company's OATT.	
Energy Charges:	
System Benefits	$0.000433 per kWh
Fuel and Purchased Power:	
Summer, all kWhs	$0.032577 per kWh
Winter, all kWhs	$0.025077 per kWh

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

Tucson Electric Power

The Energy People

Pricing Plan LLP-14
Large Light and Power Service

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added 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 the Company 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.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

Tucson Electric Power

The Energy People

Pricing Plan LLP-85N
Large General Service Time-of-Use

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service unless otherwise addressed by specific rate schedules, when all energy is supplied at one point of delivery and through one metered service. Not applicable to resale, breakdown, standby, or auxiliary service.
Service under this pricing plan will commence when the appropriate meter has been installed.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

PRICE SCHEDULE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge	$371.87 per month
Demand Charges (includes Generation Capacity):	
Summer On-peak	$11.869 per kW
Summer Off-peak (applies to all off-peak demand bill determinates)	$ 8.239 per kW
Winter On-peak	$8.908 per kW
Winter Off-peak Demand (applies to all off-peak demand bill determinates)	$ 6.418 per kW

Note:
1. *For demand billing, "on-peak demand" shall be based on demand measured during both peak and shoulder peak periods.*
2. *For demand billing, "off-peak demand" shall be based on demand measured during the off- peak periods.*
3. *Unlike Schedules LLP Rates 85A, 85F,90A, 90F, and 90N, the demand charges above are NOT excess demand charges; they apply to all Off-Peak kW, not just Off-Peak kW in excess of 150% of Peak kW.*

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Pricing Plan LLP-85N
Large General Service Time-of-Use

Energy Charges (excluding Fuel and Purchased Power):

	Summer (May – October)	Winter (November - April)
On-Peak	$0.007500	$0.002500
Shoulder-Peak	$0.005000	N/A
Off-Peak	$0.002500	$0.000000

The Summer periods below apply on all days for consumption-based (kWh-based charges) charges.

On-Peak is 2:00 p.m. to 6:00 p.m.
Shoulder-Peak is 12:00 p.m. (noon) to 2:00 p.m. and 6:00 p.m. to 8:00 p.m. (included with On-Peak for demand-based (kW-based) charges).
Off-Peak is 12:00 a.m. (midnight) to 12:00 p.m. (noon) and 8:00 p.m. to 12:00 a.m. (midnight)

The Winter periods below apply on all days for consumption-based (kWh-based charges) charges.

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.
Shoulder-Peak: there are no shoulder peak periods in the winter.
Off-Peak is 12:00 a.m. (midnight) to 6:00 a.m., 10:00 a.m. to 5:00 p.m., and 9:00 p.m. to 12:00 a.m. (midnight)

Fuel and Purchased Power (per kWh):

	Summer (May – October)	Winter (November - April)
On-Peak	$0.059253	$0.036088
Shoulder-Peak	$0.033588	N/A
Off-Peak	$0.025299	$0.027799

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

SHOULDER CONSUMPTION (kWh) IN OCTOBER

Any shoulder consumption (kWh) remaining from October usage shall be billed at the summer shoulder price in following billing months.

Tucson Electric Power
The Energy People

Pricing Plan LLP-85N
Large General Service Time-of-Use

BILLING DEMAND

For demand billing, on-peak demand shall be based on demand measured during both peak and shoulder peak periods.

The billing demand shall be specified in the contract, but shall not be less than 200 kW. Additionally, the On-Peak billing demand shall not be less than 50.00% of the maximum On-Peak billing demand in the preceding eleven months, unless otherwise specified in the contract.

PRIMARY SERVICE

The rates contained in this schedule reflect secondary service and shall be subject to a primary discount of 20.6 cents per kW per month (on the bundled rate, with the discount take from the unbundled kW delivery charge) on the billing demand each month.

POWER FACTOR ADJUSTMENT

The above rate is subject to a discount or a charge of 1.3¢ per kW of billing demand for each 1% the average monthly power factor is above or below 90% lagging to a maximum discount of 13.0¢ per kW of billing demand per month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:	
Meter Services	$223.13 per month
Meter Reading	$ 18.59 per month
Billing & Collection	$111.56 per month
Customer Delivery	$ 18.59 per month
Demand Charges ($/kW)	
Generation Capacity Charges (in $/kW)	
Summer On-peak	$ 5.530 per kW
Summer Off-peak (applies to all off-peak demand bill determinates)	$ 3.030 per kW
Winter On-peak	$ 4.530 per kW
Winter Off-peak Demand (applies to all off-peak demand bill determinates)	$ 2.030 per kW
Delivery Charges (in $/kW)	
Summer On-peak	$ 3.561 per kW
Summer Off-peak (applies to all off-peak demand bill determinates)	$ 2.873 per kW

Tucson Electric Power
The Energy People

Pricing Plan LLP-85N
Large General Service Time-of-Use

Winter On-peak	$ 2.351 per kW
Winter Off-peak Demand (applies to all off-peak demand bill determinates)	$ 2.363 per kW
Fixed Must Run Charges (in $/kW)	
Summer & Winter; On-peak kW	$ 0.315 per kW
Summer & Winter; Off-peak kW (applies to all off-peak demand bill determinates)	$ 0.314 per kW
System Benefits Charges (in $/kW)	
Summer & Winter; On-peak kW	$ 0.043 per kW
Summer & Winter; Off-peak kW (applies to all off-peak demand bill determinates)	$ 0.042 per kW
Transmission (in $/kW)	
Summer On-peak Demand	$ 1.887 per kW
Summer Off-peak Demand	$ 1.544 per kW
Winter On-peak Demand	$ 1.301 per kW
Winter Off-peak Demand	$ 1.301 per kW
Transmission - Ancillary Services 1 System Control & Dispatch	
Summer On-peak Demand	$ 0.026 per kW
Summer Off-peak Demand	$ 0.021 per kW
Winter On-peak Demand	$ 0.018 per kW
Winter Off-peak Demand	$ 0.018 per kW
Transmission - Ancillary Services 2 Reactive Supply and Voltage Control	
Summer On-peak Demand	$ 0.101 per kW
Summer Off-peak Demand	$ 0.083 per kW
Winter On-peak Demand	$ 0.070 per kW
Winter Off-peak Demand	$ 0.070 per kW
Transmission - Ancillary Services 3 Regulation and Frequency Response	
Summer On-peak Demand	$ 0.098 per kW
Summer Off-peak Demand	$ 0.080 per kW
Winter On-peak Demand	$ 0.067 per kW
Winter Off-peak Demand	$ 0.067 per kW
Transmission - Ancillary Services 4 Spinning Reserve Service	
Summer On-peak Demand	$ 0.265 per kW
Summer Off-peak Demand	$ 0.217 per kW
Winter On-peak Demand	$ 0.183 per kW

Tucson Electric Power
The Energy People

Pricing Plan LLP-85N
Large General Service Time-of-Use

Winter Off-peak Demand $ 0.183 per kW

Transmission - Ancillary Services 5 Supplemental Reserve Service

Summer On-peak Demand	$ 0.043 per kW
Summer Off-peak Demand	$ 0.035 per kW
Winter On-peak Demand	$ 0.030 per kW
Winter Off-peak Demand	$ 0.030 per kW

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Energy Charges ($/kWh):
Delivery Charges (in $/kWh):

	Summer (May – October)	Winter (November - April)
On-Peak	$0.007500	$0.002500
Shoulder-Peak	$0.005000	N/A
Off-Peak	$0.002500	$0.000000

Fixed Must Run and Systems Benefits charges are recovered under demand components above.

Fuel and Purchased Power (per kWh):

	Summer (May – October)	Winter (November - April)
On-Peak	$0.059253	$0.036088
Shoulder-Peak	$0.033588	N/A
Off-Peak	$0.025299	$0.027799

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

Tucson Electric Power
The Energy People

Pricing Plan LLP-85N
Large General Service Time-of-Use

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added 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 the Company 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.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.