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BEFORE THE ARIZONA CORPORATIO[illegible]

COMMISSIONERS

BOB STUMP - Chairman
GARY PIERCE
BRENDA BURNS
BOB BURNS
SUSAN BITTER SMITH

Arizona Corporation Commission
DOCKETED
JUN 27 2013
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IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-12-0291 DECISION NO. 73912 **OPINION AND ORDER**

DATES OF HEARING:	March 4, 2013 (Public Comment); March 6, 7, and 8, 2013 (Hearing)
PLACE OF HEARING:	Tucson, Arizona
ADMINISTRATIVE LAW JUDGE:	Jane L. Rodda
IN ATTENDANCE:	Bob Stump, Chairman Gary Pierce Brenda Burns Bob Burns Susan Bitter Smith
APPEARANCES:	Bradley S. Carroll and Philip J. Dion, Tucson Electric Power, and 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; Timothy M. Hogan, Arizona Center for Law in the Public Interest, on behalf of Southwest Energy Efficiency Project and The Vote Solar Initiative; Lawrence V. Robertson, Jr., of Counsel to Munger Chadwick, PLC, on behalf of EnerNOC, Inc., the Southern Arizona Home Builders Association, and Southern Arizona Water Users Association;

C. Webb Crockett, Fennemore Craig, PC, on behalf of Freeport-McMoRan Copper & Gold, Inc. and Arizonans for Electric Choice and Competition;

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

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

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

Robert J. Metli, Munger Chadwick, PLC, on behalf of Opower, Inc.; and

Robin Mitchell, Charles Hains and Brian Smith, Staff Attorneys, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

BY THE COMMISSION:

On July 2, 2012, Tucson Electric Power Company ("TEP" or "Company") filed with the Arizona Corporation Commission ("Commission") an application for the establishment of just and reasonable rates to realize a reasonable rate of return on the fair value of its operations in Arizona ("Rate Application"). The Rate Application requested an increase in base rates of $127.8 million, or 15.3 percent, to become effective July 1, 2013. The requested increase was based on the Company's adjusted sales and expenses for the twelve months ended December 31, 2011 ("test year").

On August 2, 2012, the Commission's Utilities Division ("Staff") notified the Company that its Rate Application was sufficient under A.A.C. R14-2-103 and classified TEP as a Class A utility.

On August 3, 2012, TEP and Staff filed a Request for Procedural Schedule and submitted a proposed schedule.

On August 6, 2012, the Residential Utility Consumer Office ("RUCO") filed a Response to the Joint Request for Procedural Schedule, suggesting modification of the proposed schedule.

On August 6, 2012, Staff and TEP filed a Proposed Form of Public Notice.

On August 13, 2012, TEP, Staff and RUCO filed a Revised Proposed Procedural Schedule.

On August 17, 2012, intervention was granted to RUCO, the Southern Arizona Homebuilders Association ("SAHBA"), Freeport-McMoRan Copper & Gold, Inc. and Arizonans for Electric Choice and Competition (collectively "AECC"), EnerNOC, Inc. ("EnerNOC"), The Kroger Co. ("Kroger"), and Arizona Public Service Company ("APS"). The same date, TEP docketed a Notice of Errata, providing corrected bill impact schedules.[1]

By Procedural Order dated August 17, 2012, a Procedural Conference for the purpose of discussing the schedule convened on August 28, 2012, at the Commission's Tucson office. Appearing through counsel were TEP, RUCO, APS, AECC, and Staff. In addition, also appearing were counsel for prospective intervenors the Southwest Energy Efficiency Project ("SWEEP"), the International Brotherhood of Electrical Workers Local 1116 ("IBEW Local 1116"), and the Sierra Club.

On August 23, 2012, SWEEP and IBEW Local 1116 filed requests to intervene.

On August 28, 2012, the Sierra Club filed a Petition to Intervene.

By Procedural Order dated September 6, 2012, SWEEP, IBEW Local 1116 and the Sierra Club were granted intervention, the matter was set for hearing on March 6, 2013, and other procedural guidelines and timelines were established. A Public Comment meeting was set for March 4, 2013, at the Commission's offices in Tucson.

The Department of Defense and all other Federal Executive Agencies ("DOD") was granted intervention on September 25, 2012. Arizona Investment Council ("AIC") was granted intervention on September 28, 2012.

On October 9, 2012, TEP filed an Affidavit of Publication attesting that notice of the hearing in this matter was published in the *Arizona Daily Star* on October 1, 2012; posted in the Joel Valdez Main Library in Tucson, Arizona on September 14, 2012; and posted on the TEP website.

On November 5, 2012, intervention was granted to Cynthia Zwick and the Southern Arizona Water Users Association ("SAWUA").

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[1] TEP also filed a Notice of Revision to Proposed Form of Notice.

On November 6, 2012, TEP filed a Notice of Filing Affidavit of Mailing indicating that TEP mailed the public notice as a bill insert beginning on October 2, 2012, and ending on October 31, 2012.

On November 14, 2012, The Vote Solar Initiative ("Vote Solar") was granted intervention.

On November 21, 2012, the Solar Energy Industries Association ("SEIA") was granted intervention.

On December 13, 2012, the Arizona Solar Energy Industries Association ("AriSEIA") was granted intervention.

On December 21, 2012, Staff, AECC, AIC, EnerNOC, IBEW Local 1116, Kroger, Opower, RUCO, SAHBA, Sierra Club and SWEEP filed direct non-rate design testimony.

On December 28, 2012, intervention was granted to Opower, Inc. ("Opower").

On January 8, 2012, TEP filed a Notice of Settlement Discussions.

On January 11, 2013, Staff, AECC, DOD, Kroger, RUCO, SAWUA, SEIA, SWEEP, Vote Solar and Ms. Zwick filed direct testimony regarding rate design and cost of service.

Settlement discussions began on January 15, 2013. On January 22, 2013, Staff filed a Notice of Filing Status Update and Proposed Process for Commission Review of Preliminary Term Sheet, to which Staff attached a Preliminary Term Sheet of a proposed settlement in principle. Staff suggested that the matter be considered at a Special Open Meeting to allow the Commission to give parties immediate input as to the settlement framework and possible direction for a settlement agreement.

The Commission reviewed and discussed the Preliminary Term Sheet in a Special Open Meeting on January 23, 2013.

On February 1, 2013, Commissioner Gary Pierce filed a letter to the docket concerning the Energy Efficiency provisions of the Preliminary Settlement Term Sheet.

On February 4, 2013, a proposed Settlement Agreement ("Settlement Agreement" or "Settlement") was docketed. The Settlement Agreement was signed by TEP, Staff, RUCO, SAHBA, Kroger, Freeport-McMoRan, AECC, EnerNOC, IBEW Local 1116, Cynthia Zwick, AIC, Opower, and Vote Solar.

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SWEEP, Sierra Club and APS participated in settlement discussions but did not sign the Settlement Agreement. APS states that it neither supports nor opposes the Settlement Agreement.[2]

On February 14, 2013, TEP filed an affidavit of posting the Public Comment Meeting as a bill message on customers' bills beginning January 2, 2013, and ending on February 1, 2013.

On February 15, 2013, TEP, AECC, RUCO, IBEW Local 1116, Cynthia Zwick, AIC, SAHBA, SAWUA, EnerNOC, Opower, Vote Solar and Staff filed testimony in support of the Settlement Agreement, and SWEEP filed testimony in partial opposition to the Settlement Agreement.[3]

On March 1, 2013, TEP, AECC and SWEEP filed Responsive Testimony regarding the Settlement Agreement.

On March 1, 2013, TEP filed an updated version of the Settlement Agreement which included an updated cover page that includes all signatories (including those who signed on and after February 4, 2013, i.e. DOD, SAWUA, AriSEIA and SEIA); an updated Attachment "D" which is the Plan of Administration ("POA") for the Energy Efficiency Resource Plan; an updated Attachment "F," the Lost Fixed Cost Recovery ("LFCR") Plan of Administration; an updated Attachment "J" regarding rate design; and an updated Attachment "K" which is the Statement of Charges.

The Commission held a Public Comment Meeting on March 4, 2013, starting at 5:30 p.m. at its Tucson offices.

The evidentiary hearing on the Settlement Agreement commenced on March 6, 2013, and continued on March 7 and 8, 2013. David Hutchens, the Company's President, and Dallas Dukes, the Company's Senior Director of Pricing and Economic Forecasting Groups, testified on behalf of TEP; Steve Olea, Director of the Commission's Utilities Division, and Howard Solganick, a consultant with Energy Tactics & Services, Inc., testified for Staff; Patrick Quinn, the Director of RUCO, testified on behalf of RUCO; Gary Yaquinto, the President of AIC, testified on behalf of AIC; Kevin Higgins, a principal in the consulting firm Energy Strategies, testified on behalf of AECC; David Goldewski, President of SAHBA testified for SAHBA; Richard Darnall, executive consultant with

[2] Transcript of the Hearing ("Tr.") at 207.

[3] On February 15, 2013, Sierra Club filed a Notice that it was not filing testimony in connection with the proposed Settlement Agreement, and joined in SWEEP's opposition.

Utilities Consulting Group, LLC, testified on behalf of SAWUA; Mona Tierny-Lloyd, Director of Regulatory Affairs for EnerNOC, testified for EnerNOC; Cynthia Zwick testified on her own behalf; Rick Gilliam, Director of Research, testified for Vote Solar; and Jeff Schlegel, Arizona's representative to SWEEP, testified for SWEEP. The pre-filed testimony in support of the Settlement Agreement of Frank Grijalva, Business Manager/Financial Secretary for IBEW Local 1116, was admitted into evidence by stipulation of the parties, as was the testimony of Diana Genasci, Manager of Opower Market Development and Regulatory Affairs. In addition to the testimony filed in support of and in opposition to the Settlement Agreement, the pre-settlement pre-filed testimony of all parties was admitted.[4]

On March 18, 2013, TEP filed Late-Filed Exhibits as discussed during the hearing, including the numerical values used to create the graph set forth on page 20 of David Hutchen's Direct Testimony in Support of the Settlement Agreement (Ex TEP-9); the estimated monthly bill impacts for the LFCR mechanism, the Environmental Compliance Adjustor and the Demand Side Management Surcharge ("DSMS") (Ex TEP-10) and a revised version of Exhibit DGH-2 to David Hutchen's Direct Testimony in Support of the Settlement Agreement addressing the specific percentage rate for the DSMS to be applied to the non-residential customer bills (Ex TEP-11).

On March 21, 2013, SAHBA, EnerNOC and SAWUA filed Initial Briefs.

On March 22, 2013, TEP, AECC, SWEEP, IBEW Local 1116, Vote Solar, Sierra Club, AIC and Staff filed Initial Briefs; AECC filed a Joinder in TEP's Initial Brief and provided an additional clarifying statement; and RUCO filed a Supplemental Brief to TEP's Closing Brief.

On March 29, 2013, TEP filed a notice that it would not be filing a Post-Hearing Reply Brief. Opower filed a Responsive Brief and Partial Joinder in TEP's Closing Brief; and SWEEP filed a Reply Brief.

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[4] Signatories to the Settlement Agreement DOD and SEIA filed Direct Testimony prior to the Settlement but did not file testimony in support of the Settlement Agreement.

DISCUSSION

TEP's Rate Application

In its Rate Application, TEP proposed a net increase in base rates of $127.8 million, or 15.3 percent, over TEP's adjusted test year retail sales.[5] TEP's revenue requirement was based on a Fair Value Rate Base ("FVRB") of $2.28 billion, which was the average of an Original Cost Rate Base ("OCRB") of $1.52 billion and the Reconstruction Cost New Less Depreciation ("RCND") Rate Base of $3.04 billion. TEP employed a pro forma capital structure comprised of 54 percent long term debt and 46 percent common equity, with a Cost of Debt of 5.18 percent, and Cost of Equity of 10.75 percent, which produced a Weighted Average Cost of Capital ("WACC") of 7.74 percent.[6] TEP proposed a Fair Value Rate of Return ("FVROR") of 5.68 percent, which assumed a return on the fair value increment of 1.56 percent.[7] TEP reported that as a result of its requested increase, the monthly bill for an average TEP residential customer using 767 kWh per month would increase 12.5 percent, from $85.17 to $95.82.[8]

TEP proposed significant changes to its rate design, which included increasing the monthly customer charge for all customer classes to allow for a greater recovery of the Company's fixed costs through fixed charges. TEP also sought to simplify its tariffs by consolidating multiple tariffs and eliminating tariffs that have been frozen.[9] TEP proposed to eliminate the recovery of any fuel or purchased costs through its base rates and to recover those costs solely through the Purchased Power and Fuel Adjustor Clause ("PPFAC") and to modify and simplify its low-income Lifeline program.

Currently, TEP has a single PPFAC rate applicable to all customers at all times, but also has 83 fuel component rates contained within base rates. TEP proposed to reduce the 83 fuel component rates to 16 different PPFAC rates based on the voltage at which customers receive service, on-peak and off-peak usage, and winter and summer periods. In addition, TEP requested to recover some

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[5] Ex TEP-7 Dallas Dukes Dir at 4; Application at 5.

[6] TEP's actual test year capital structure was 56.6 percent long-term debt and 43.5 percent equity. The pro forma capital structure utilized in TEP's last rate case contained 57.5 percent debt and 42.5 percent equity. Application at 6.

[7] Ex TEP-7 Reed Dir at 45-48.

[8] Ex TEP-7 Application at 5, as modified by August 17, 2012 Errata.

[9] The Company has over 50 different basic rates and there are multiple options within many of those rates. TEP believed that the multiplicity of rates has led to customer confusion and a high administrative burden on the Company, and asserts that its proposed rates are designed to give more accurate and timely price signals to customers. Application at 7.

additional costs through the PPFAC including credit support costs, wholesale energy broker fees, greenhouse gas costs and incremental lime costs above those included in base rates.[10]

TEP also proposed an LFCR mechanism which it stated is similar to the LFCR approved for UNS Gas, Inc. in Decision No. 73142 (May 1, 2012) and for APS in Decision No. 73183 (May 24, 2012).[11] The Company argued it needs such a mechanism, or something similar, to mitigate the negative financial impacts of complying with the Electric Energy Efficiency ("EEE Rules") and the rising number of Distributed Generation ("DG") resources in TEP's service territory resulting from the Renewable Energy Standard Tariff ("REST") Rules.[12]

TEP proposed an Energy Efficiency Resource Plan ("EERP") under which the Commission would approve a three-year energy efficiency ("EE") program budget. The program costs would be treated as a regulatory asset that would be amortized over four years. TEP stated that because it would amortize its EE costs over a four-year period, the EERP would allow the DSMS to be significantly lower from 2014 through 2016 than if EE annual expenses were fully recovered each year as under the current practice. The Company stated that it would determine the most cost-effective EE option appropriate for its particular system, invest capital to procure that resource and recover the associated costs—including the amortization expense and an appropriate return on investment – through the DSMS. TEP claimed this capital investment and recovery model is similar to that used for any other supply-side resource, and would reduce and stabilize the rate impacts, better synchronize the benefits of EE with their costs, provide a base level of certainty to program offerings, and eliminate the need to provide a performance incentive.[13]

TEP also proposed an Environmental Compliance Adjustor ("ECA") to provide more timely recovery of substantial upcoming capital expenditures necessary to meet new government mandated environmental regulations for pollution control equipment and efficiency projects at the Company's power plants. To comply with federal rules, TEP anticipates: 1) approximately $200 million in capital costs and $3-6 million in annual O&M costs to comply with the Regional Haze mandates at

[10] Ex TEP-7 Application at 7-8. Lime is used to remove sulfur dioxide from emissions and TEP states that its use is directly linked to fuel consumption.
[11] Ex TEP-7, Hutchens Dir at 10.
[12] Ex TEP-7 Application at 8.
[13] Ex TEP-7 Application at 9.

the San Juan Generating Station; 2) approximately $86 million in capital costs and $2-4 million in annual O&M costs to comply with the Regional Haze and Environmental Protection Agency ("EPA") Mercury and Air Toxics Standards ("MATS") rule mandates affecting the Navajo Generating Station; 3) approximately $36 million in capital costs and $2-4 million in annual O&M costs to comply with the Regional Haze and the MATS rule mandates for the Four Corners Plant; and 4) approximately $5 million in capital costs and $3 million in annual O&M costs to comply with the MATS rules for the Springerville Generating Station ("SGS"). TEP asserts that given the magnitude of the capital outlays, TEP cannot afford to wait several years to recover the costs in the next general rate case, and that recovering these environmental costs as they are incurred through an adjustor mechanism would moderate the rate impact of such large capital investments on customers.[14]

TEP requested authorization to invest up to $30 million annually for the development of TEP-owned renewable energy resources and to allow TEP to receive recovery of related expenses through the REST surcharge.[15] TEP states that this authorization is similar to the authority previously provided by the Commission in connection with the Company's currently approved REST Implementation Plans, and that the Company is requesting this recovery mechanism between 2014 and 2017 or until the next rate case, to provide it with a "more balanced, comprehensive and efficient" renewable energy procurement process "because it is not practical to procure such resources on a year-to-year timeframe as contemplated under the current REST rules."[16] The Company proposed to transfer into rate base its renewable generation assets previously approved under its REST Implementation Plan's Bright Tucson Solar Buildout Program.

Pre-Settlement Positions of Parties

RUCO

In its pre-Settlement testimony, RUCO recommended a revenue increase of $26.8 million, an increase of 3.1 percent over test year revenues.[17] RUCO proposed an OCRB of $1,237 million and a FVRB of $1,910 million.[18] RUCO recommended adopting TEP's actual test year capital structure

[14] Ex TEP-7 Application at 10-11.
[15] Ex TEP-7 Application at 11.
[16] Ex TEP-7 Application at 11.
[17] Ex RUCO-6 Mease Dir at i.
[18] Ex RUCO-6 Mease Dir at RBM-1.

with a cost of long-term debt of 5.22 percent, cost of short-term debt of 1.42 percent and cost of equity of 10.0 percent, resulting in a 7.28 percent WACC. RUCO recommended a FVROR of 5.11 percent, which was RUCO's 7.28 percent OCRB rate of return less its recommended inflation adjustment of 2.17 percent.[19]

RUCO did not agree with making changes to the PPFAC as proposed by the Company because RUCO did not believe that adding other costs to the PPFAC adjustor added value to the ratepayer, and believed that having a portion of fuel costs embedded in base rates creates an appropriate sharing of risk between the shareholder and ratepayer.[20] RUCO agreed with the concept of the LFCR mechanism but recommended several modifications—specifically, a one percent cap and allowing any excess to be deferred until a future period, and a maximum increase of no more than one percent for the opt-out tariff.[21] RUCO opposed the EERP as proposed by the Company because: 1) by capitalizing program costs and applying carrying costs, the ratepayers may end up paying more for the EE programs than if the costs were expensed annually; 2) the rate of return plus 200 basis points premium that was applied to the DSM/EE program costs constituted a performance incentive that was not based on actual performance and rewarded spending over the EE savings; 3) the three year term unnecessarily bound future Commissions to spending levels and program structure; and 4) the proposed EERP eliminated significant Commission oversight.[22]

AECC

In its pre-Settlement Direct Testimony, AECC recommended that TEP's revenue requirement be reduced by at least $44.525 million from the $127.3 million base rate increase proposed by the Company.[23] AECC recommended rejecting TEP's proposal to change the structure of the PPFAC and to consider adopting a 70/30 risk-sharing mechanism. AECC recommended against adopting the LFCR mechanism as proposed, and suggested the following modifications: 1) exclude larger customers from the LFCR program and recover their fixed delivery costs through rate design; 2) limit

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[19] Ex RUCO-10 Rigsby Dir at i.
[20] Ex RUCO- 6 Mease Dir at 32-33.
[21] Ex RUCO-6 Mease Dir at 37-38. RUCO noted that the lowest proposed opt-out rate of $2.50 would be a 2.6 percent increase for the average ratepayer.
[22] Ex RUCO - 6 Mease Dir at 39-40.
[23] Ex AECC- 1 Higgins Dir at 4.

the LFCR to unbundled delivery service revenues; and 3) in order to recognize load growth, limit kWhs used for measuring going-forward lost revenue recovery to the lesser of EE improvements attributable to TEP programs or actual net reductions in retail kWhs sold relative to the retail kWhs used in setting rates in order to recognize load growth.[24]

AECC argued that TEP's proposed ECA was an example of unwarranted single-issue ratemaking and should be rejected. AECC did not object to TEP's proposal to amortize recovery of EE expenses over four years, but recommended rejecting the proposed Return on Equity ("ROE") premium of 200 basis points. AECC further recommended that on a going-forward basis, the overall costs of TEP's EE programs be kept within 3.0 percent of customers' total bills and that the DSMS for non-residential customers be assessed on an equal percentage basis.[25] With respect to the net operating loss ("NOL") carry-forward, AECC recommended that the Commission recognize the accumulated deferred income tax assets as proposed by TEP, but also require TEP to establish a regulatory liability when bonus tax depreciation associated with plant included in rate base in this case is applied against future tax years. Finally, AECC recommended that the Commission deny TEP's request for approval of four consecutive years of solar project investments because AECC believes it is essential that the Commission retain direct control over each year's REST budget.[26]

Staff

In its pre-Settlement Direct Testimony, Staff recommended that TEP be authorized a base rate increase of $76.406 million, which was near the lower end of the two fair value options that Staff calculated. Under Staff's Option 1, which utilized a FVROR of 4.63 percent, the revenue increase would be $75.405 million. Under Staff's Option 2, the FVROR for TEP was 4.86 percent and the revenue deficiency was approximately $84.036 million. The base rate increase of $75.405 million (under Option 1) and $84.036 million (under Option 2) equate to percentage increases of approximately 9.06 percent and 10.10 percent over TEP's adjusted retail revenues at current rates, respectively.[27] Staff recommended using TEP's actual capital structure and recommended a cost of

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[24] Ex AECC-1 Higgins Dir at 5.
[25] Ex AECC - 1 Higgins Dir at 6.
[26] Ex AECC- 1 Higgins Dir at 6.
[27] Ex Staff-1 Smith Dir at Executive Summary.

equity of 9.4 percent, and an overall cost of capital of 7.00 percent before the FVRB adjustment. Staff recommended a rate of return between 0.0 percent and 0.68 percent on the FVRB Increment which resulted in an overall FVROR of between 4.63 and 4.86 percent.[28]

Staff had a number of regulatory and policy concerns involving the Company's proposed EERP, including : 1) that the forward-looking concept proposed by TEP should be rejected; 2) the 200 basis point increase to the ROE is excessive and unnecessary; 3) because cost-recovery would be virtually secured, Staff believed it was unclear that the proposed EERP would provide incentives to maximize the results of the program and, at the same time, provide cost-effective and efficient implementation of the programs; 4) the proposal would require that the Commission issue one or more waivers of various requirements of A.A.C. R14-2-2405 (annual implementation plans) and A.A.C. R14-2-2410 (monitoring plan); and 5) the EERP appeared to be an attempt to mitigate the effects of regulatory lag.[29] Staff recommended that the Commission adopt the concept of establishing a regulatory asset for approved EE implementation costs that TEP incurs to achieve the Commission's EE goal. Under Staff's proposal, the Company would earn a return on that investment at a rate no greater than the Commission-approved WACC in this proceeding; the amortization period would be seven years on a rolling basis and would trued-up each year by adjusting the Company's DSMS to reflect any under or over-recoveries.

Staff disagreed that there was a need for the proposed ECA because the Company offered no evidence that its cash flows were unable to sustain the needed capital requirements. Staff recommended that the Commission reject the ECA as proposed because it was too broad and included capital investments that were not yet mandated or whose compliance dates were well outside the timeframe in which the Company was likely to request another base rate increase. Because the Company has several major projects in the next two-to-three years, and to be consistent with the treatment that APS received, Staff recommended that if the Commission approved an environmental tracker for TEP, that it should mirror the Environmental Improvement Surcharge ("EIS") granted to APS in Decision No. 73183, and that it should include a cap.[30]

[28] Ex Staff- 3 Berry Dir at 3.
[29] Ex Staff-9 McGarry Dir at Executive Summary.
[30] Ex Staff- 9 McGarry Dir at Executive Summary

Staff recommended that the Commission modify TEP's LFCR proposal to: 1) allow the Company to recover only distribution (delivery) service fixed charges; 2) cap the increased revenue allowed for each year at one percent; 3) recover the lost fixed cost revenue on a percentage of revenue basis; and 4) make the LFCR mechanism effective beginning with the effective date for rates in this proceeding.[31]

As a result of Staff's field investigation, Staff concluded that TEP's Call Center performs effectively and efficiently in response to outage notifications and customer bill inquiries and that TEP's Outage Management System is appropriate to TEP. Staff recommended that TEP: 1) consider increasing the number of distribution circuits to be upgraded annually (currently at one); 2) perform a study of potential line loss reductions for upgrading one to three 4kV circuits prior to implementing a broad distribution system upgrade; 3) continue upgrading toward smart metering AMI meters; 4) move toward equipping its feeder circuits with meters to provide comparable data to what is provided by the circuit metering on TEP's distribution circuits; 5) establish a routine for periodic load-flow analysis to its distribution system and confirm that the system circuit model is accurate; and 6) use any future circuit breaker operation in the distribution system to confirm that the correct indication appears on the Supervisory Control and Data Acquisition ("SCADA") display of breaker positions.[32]

Staff's review included TEP's proposed changes to its PPFAC, its fuel and purchased power policies and procedures, its power plant performance and inventory cost assumptions in base rates.[33] Staff agreed with TEP's proposal to include brokerage fees, and the proceeds from emission allowance sales in the PPFAC as well as an extension of the monthly filing period from 30 to 45 days. Staff recommended that the costs associated with the insurable event at the San Juan mine not flow through the PPFAC until after the insurance coverage has been determined and the claim paid, and then only if the non-insurable portion cannot be recovered in another manner and/or is deemed to be prudent. Staff recommended revising the PPFAC POA to incorporate the documentation recommendations from TEP's internal Compliance Audit and that the POA be revised to require management audits. Staff found that the costs of TEP's fuel and power purchases since 2009 were

[31] Ex Staff -11 Solganick Dir at Executive Summary.
[32] Ex Staff- 7 Lewis Dir at iv-v.
[33] Ex Staff- 5 Medine Dir.

prudently incurred. Staff recommended that TEP update the Hedging Policy to reflect current market conditions and produce a Hedging Plan consistent with the Hedging Policy; that the Risk Manager not have any commercial duties; and that the Risk Manager and Risk Controller have different reporting lines consistent with leading industry practices.[34]

Staff found that TEP has not been successful in managing its inventory levels, citing the Sundt Plant coal stockpiles that were consistently above target levels as the result of the strategic decision to burn gas, and the extended period when inventory at SGS was below target. Staff concluded that overall, with the exception of Sundt, the TEP plants generally performed in the top 50 percent of the Western Electricity Coordinating Council ("WECC") coal plants. Staff generally agreed with TEP's methodology for determining the amount of coal to include in base rates, but proposed adjustment to the coal prices. Finally with respect to procurement, Staff noted that there is uncertainty as to the status of several of TEP's coal plants because of the costs to retrofit to reduce emissions. Staff asserted that to the extent any of the units are retired early, there may be fuel-related cost consequences and recommended that TEP develop a plan to address potential costs and strategies for mitigating costs in such event.

DOD

The DOD focus in this proceeding was on cost of service principles and rate design.[35] DOD criticized TEP's Cost of Service Study in this proceeding claiming that it was skewed in favor of the small commercial class and contained load data and allocation errors.[36] DOD asserted that the Company's proposed rates for the larger customers were not cost-based, and while DOD supported the consolidation of rates where possible, it argued that the proposed 100 percent demand ratchet failed to match price with cost, and argued that TEP did not provide any cost justification to support a 100 percent demand ratchet.[37]

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[34] Ex Staff-5 Medine Dir at Executive Summary.
[35] Ex DOD - 1 Neidlinger Dir at 2.
[36] Ex DOD-1 Neidlinger Dir at 6-14.
[37] Ex DOD- 1 Neidlinger Dir at 15. According to DOD, a demand ratchet is a proxy for seasonal rates for utilities that exhibit wide divergences in seasonable loads, and that the ratchet establishes a customer's minimum monthly demand charge based on the customer's maximum monthly peak demand during a consecutive 12 month period. The purpose of a demand ratchet is to ensure that customers pay demand charges during the off-peak season consistent with seasonal load relationships.

Kroger

Kroger has approximately 22 stores and other facilities in TEP's service territory which consume in excess of 48 million kWhs per year.[38] Kroger's pre-Settlement testimony focused on the Company's proposal to implement an LFCR mechanism. Kroger recommended that the Commission not adopt an LFCR mechanism, but if the Commission did, such mechanism should not apply to large customer rate schedules that have kW demand charges because the demand charges are designed to recover most fixed costs.[39]

Sierra Club

Sierra Club's pre-Settlement testimony focused on TEP's proposed ECA. Sierra Club concluded that the ECA as proposed would allow TEP to recover costs associated with new investments in adding and acquiring new generating capacity as well as environmental emissions controls, without waiting for TEP's next rate case. Sierra Club asserted that under TEP's proposed procedure, ratepayers could pay for months, or years, for imprudently incurred costs.[40] Sierra Club argued that TEP failed to allow for the risks and uncertainties in the coal plant analysis presented in its 2012 Integrated Resource Plan ("IRP") and consequently, the IRP is not adequate to determine whether the large expenditures that the Company testified it will need to retrofit its existing coal plants are economically justified. In addition, Sierra Club asserted that TEP did not present any analysis of the impact that adopting the ECA would have on financing costs, nor did TEP demonstrate that its proposed ECA would reduce the number or frequency of general rates cases or that such a reduction would benefit ratepayers. Sierra Club recommended rejecting the proposed ECA and instead require TEP to seek recovery of environmental compliance expenditures by demonstrating prudence in a general rate case. In addition, Sierra Club recommended that all interested parties have a reasonable opportunity to review and if they desire, to present expert testimony in TEP's plans for major environmental upgrades, plant divestitures or retirement decisions, or resource acquisition decisions before they are made.[41]

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[38] Ex Kroger-1 Baron Dir at 5.
[39] Ex Kroger- 1 Baron Dir at 6.
[40] Ex Sierra Club- 1 Schlissel Dir at 3.
[41] Ex Sierra Club-1 Schlissel Dir at 4.

Vote Solar

Vote Solar is a non-profit grassroots organization working to foster economic opportunity, promote energy independence and fight climate change by making solar a mainstream energy resource across the United States.[42] Vote Solar has almost 2,500 members in Arizona, with 269 within TEP's service territory. Vote Solar's pre-Settlement testimony focused on how TEP's cost recovery and rate design proposals may affect current solar customers and future solar adopters in TEP's service area.

Vote Solar asserted that TEP talks about the challenges facing the industry such as economic conditions, regulatory requirements and the effect of new technologies, but continues to operate under the same traditional business and regulatory model in use for decades. Vote Solar alleged that TEP's Rate Application merely requested new rate mechanisms to provide quicker and more stable cost recovery, rather than address underlying structural changes in the industry.[43] Vote Solar expressed concerns with TEP's proposed increase in the monthly customer charge, the increase in the demand ratchet and the partial decoupling mechanism. Vote Solar asserted that TEP did not present sufficient evidence to justify a departure from current cost recovery methods, and that its proposals to increase the customer charge and demand ratchet are inconsistent with the basic principle of recovering costs based on cost causation. Vote Solar believes that a mechanism such as the LFCR would help address TEP's concerns about the volatility of revenue related to fluctuating sales levels, but expressed concerns that TEP's proposal focused on EE and DG as the sole sources of sales changes addressed by the LFCR. Vote Solar also claimed that TEP did not provide any analysis or supporting evidence to warrant the assumption in the LFCR mechanism that half (50%) of the demand-based revenues would not be recovered from commercial customers with solar generation.[44] Vote Solar stated it would support including an adjustment for "non-normal" weather related sales based on cooling degree days in the LFCR calculation, and also that a full decoupling approach would be acceptable provided the demand charge issue was appropriately addressed.[45]

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[42] Ex Vote Solar- 1 Gilliam Dir at 2.
[43] Ex Vote Solar-1 Gilliam Dir at 12.
[44] Ex Vote Solar-1 Gilliam Dir at 38.
[45] Ex Vote Solar-1Gilliam Dir at 44-45.

SWEEP

SWEEP is a public interest organization dedicated to advancing energy efficiency as a means of promoting customer benefits, economic prosperity, and environmental protection in Arizona, Colorado, Nevada, New Mexico, Utah and Wyoming.[46] SWEEP's pre-Settlement testimony focused on TEP's EE programs. For a number of reasons, the Commission did not approve TEP's 2011-2012 EE Implementation Plan or a new adjustor mechanism, and in March 2012, TEP suspended many of its EE programs because ratepayer funding to support the programs was not sufficient to cover the costs of the programs.[47] SWEEP was greatly concerned about the cuts to TEP's EE programs.

With respect to TEP's proposed EERP, SWEEP found the proposal to amortize EE as a regulatory asset acceptable because of the past instability in the EE budget and programs experienced by TEP, but had some concerns about specific aspects of the proposal that could affect the ultimate cost to ratepayers.[48] SWEEP believed that TEP's proposed four-year amortization period was an appropriate balancing of the advantages of longer-term amortization (less up-front costs) with the investor risks that come with a longer period, but SWEEP could also support a longer amortization period.[49] SWEEP supported the Company earning a return on its EE investments based on the WACC so long as that return is reasonable and consistent with other Commission rate cases. With respect to TEP's proposed 200 basis point bonus return, SWEEP's support was conditional on the bonus return being performance-based, such that the level of the bonus return would depend on the performance of TEP's EE programs.[50] SWEEP supported TEP's use of the Societal Cost Test ("SCT") to evaluate the cost-effectiveness of EE investments, but proposed modifications for how TEP applies the SCT. Specifically, SWEEP recommended that TEP's methodology better align true costs and benefits by using a true social discount rate, by including non-energy and non-market benefits, and by improving the valuation of avoided costs.[51]

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[46] Ex SWEEP-1 Schlegel Dir at 3.
[47] Ex SWEEP- 1 Schlegel Dir at 7; *see* Docket No. E-01933A-11-0055 (TEP's 2011-2012 EE Implementation Plan).
[48] Ex SWEEP- 1 Schlegel Dir at 10.
[49] Ex SWEEP-1 Schlegel Dir at 10-11.
[50] Ex SWEEP-1 Schlegel Dir at 12.
[51] Ex SWEEP-1 Schlegel Dir at 13-15.

SWEEP also advocated for full revenue decoupling in order to reduce the financial disincentive for utilities to support EE.[52] SWEEP argued that with decoupling, the financial interest of TEP would be better aligned with the interests of its customers by reducing the financial disincentives to utility support of EE resulting in more energy savings and larger reductions in customer energy bills. SWEEP asserted that under decoupling, the utility might support EE efforts that are not directly linked to its portfolio of EE programs, such as supporting building energy codes, appliance standards, energy education and marketing, state and local government energy conservation efforts, and federal energy policies.

SAWUA

SAWUA is a non-profit corporation whose membership consists of publically- and privately-owned providers of potable and wastewater services, and some who use electricity for agricultural pumping purposes.[53] SAWUA's pre-Settlement testimony focused on TEP's Schedule G, Allocated Cost of Service and Schedule H, Rate Design. SAWUA concluded that TEP's schedules G and H, as revised, provided a fair allocation of costs to the Municipal and Irrigation Pumping class of customers and that TEP's proposed rate design would allow TEP to recover an appropriate level of revenue with respect to that class of customers.[54]

SAHBA

SAHBA is a member trade organization of home builders, developers and associate members.[55] SAHBA intervened in order to inform its members about TEP's EE policies as well as influence those programs within the context of the proceeding. SAHBA found advantages for SAHBA members in TEP's EE proposals, including improved construction quality and marketing advantages, as well as incentives or rebates. SAHBA was also interested in maintaining TEP's current line extension policy.

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[52] Ex SWEEP-1 Schlegel Dir at 16-17.
[53] Ex SAWUA-1 Darnell Dir at 2.
[54] Ex SAWUA-1 Darnell Dir at 3-4.
[55] Ex SAHBA-1 Godlewski Dir at 2.

IBEW Local 1116

IBEW Local 1116 is the labor organization which serves as the exclusive representative for, *inter alia*, approximately 700 non-managerial TEP employees.[56] IBEW Local 1116 believed that TEP is entitled to a rate increase, and in particular, supported the payroll expense and payroll tax expense adjustments being proposed by the Company.[57] IBEW Local 1116 asserted that it was essential that TEP receive adequate rate relief in order to avoid hindering TEP's efforts to provide safe and reliable service to its customers or impairing its ability to maintain appropriate staffing levels.

Zwick

Ms. Zwick has been an advocate for low-income ratepayers in Arizona since 2003. Her pre-Settlement testimony urged the Commission to deny the proposed Lifeline Rate modification; to continue to exclude the Lifeline customers from the DSMS charge; to continue to allow qualified Lifeline customers to maintain their eligibility and rate if they move residence while a TEP customer; and approve an alternative means of investing and using the LIFE fund to more effectively serve the low-income customers it was originally intended to serve and support.[58]

Opower

Opower provides information-based behavioral EE programs to more than 75 utilities in 30 states. Opower stated that its Home Energy Reports program motivates customers to save an average of 1.5-3.0 percent on their energy bills. Opower's pre-Settlement testimony urged the removal of regulatory barriers to EE markets and described how regulatory uncertainty in Arizona is negatively affecting the business environment for EE. Opower supported TEP's proposed EERP because it would create a more stable and predictable business environment for companies like Opower and ensure that benefits to the ratepayers always exceed costs.[59]

EnerNOC

EnerNOC implements commercial and industrial customer energy management solutions, and has 8,500 MW of dispatchable demand response available to provide peak capacity reductions with

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[56] Ex IBEW-1 Grijalva Dir at 2.
[57] Ex IBEW-1 Grijalva Dir at 5.
[58] Ex Zwick-1 Zwick Dir at 2.
[59] Ex Opower-1 Kapis Dir at 5-6.

utilities in North America, the United Kingdom, Australia and New Zealand. EnerNOC has a contract with TEP to provide demand response services through TEP's Direct Load Control ("DLC") Program.[60] EnerNOC supported TEP's proposed LFCR and EERP. EnerNOC believed that to continue an EE Standard requires that the barriers to utility acceptance be addressed and that TEP's LFCR proposal appeared to be a reasonable approach to mitigating the risk of lost revenues.[61] EnerNOC testified that the LFCR and EERP proposals provided revenue, rate and program stability to TEP, its customers, and its contractors.

SEIA

SEIA is a national trade association of the United States solar industry.[62] The purpose of SEIA's pre-Settlement testimony was to respond to TEP's proposal to modify the Large General Service (LGS-13) Rate Schedule, Large General Service (LGS-85N) Time of Use ("TOU") Rate Schedule, and Large Light & Power (LLP-90N) TOU Rate Schedule and the Proposed LFCR mechanism. SEIA asserted that the significant changes that TEP proposed to certain commercial rate plans would severely impact existing solar customers, such as schools and businesses that have already invested in solar energy. In addition, SEIA stated the tariff changes would stifle future solar developments by making it difficult to attract financing for distributed solar energy.[63] SEIA asserted that the proposed rates reduce on-peak energy charges and dramatically increased the demand and customer charges which removed a significant incentive for conservation and reduced the value of solar generation which tends to occur during the on-peak hours. SEIA recommended that existing solar customers be grandfathered at their original rate plans and that a workshop to determine a solar-friendly rate be conducted.[64] In addition, SEIA recommended that TEP conduct a representative sampling of EE and DG customers and calculate demand-based revenues that would not be collected by commercial customers with solar generation in order to provide accurate inputs for the LFCR mechanism.[65]

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[60] Ex EnerNOC-1 Tierny-Lloyd Dir at 1.
[61] Ex EnerNOC-1 Tierny-Lloyd Dir at 7.
[62] Ex SEIA-1 Hitt Dir at 1.
[63] Ex SEIA-1 Hitt Dir at 2.
[64] Ex SEIA-1 Hitt Dir at 4.
[65] Ex SEIA-1 Hitt Dir at 5.

AIC

AIC is a non-profit association whose membership includes debt and equity investors in Arizona utilities and other Arizona businesses. AIC's mission is to advocate on behalf of its members primarily before regulatory bodies as well as the legislature and to enlarge and maximize the influence of utility investors on public policies and governmental actions that impact investors and their investments.[66] AIC filed pre-Settlement testimony to support the Company's request to implement an ECA. AIC asserted that the ECA was an "appropriate, essential and necessary component" of the proceeding because: 1) it allows more timely cost recovery of mandated environmental investments over which TEP has no control; 2) the required investments will be substantial and could equal almost one-fourth of TEP's total current rate base; and 3) the expenditures will occur over time and cause a significant drag on earnings and a substantial erosion of investor returns unless TEP can recover the costs in a more timely fashion.[67] AIC testified the ECA would provide TEP with cash flow to assist in financing the mandated projects and help with the Company's credit ratings; the ECA would adjust rates gradually rather than postponing them for a larger more abrupt recovery in the next rate case; and gradual recovery would reduce the need for TEP to file rate cases as frequently.[68]

Settlement Agreement

Following the filing of Direct Testimony by Staff and Intervenors, the Parties in this matter commenced settlement discussions on January 15, 2013. All Parties to the Docket were notified of the settlement discussion process, were encouraged to participate in the negotiations and were provided with an opportunity to participate. Seventeen parties entered into a Settlement Agreement, a copy of which is attached hereto as Exhibit A. Two parties oppose portions of the Settlement Agreement.

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[66] Ex AIC-1 Yaquinto Dir at 1-2.
[67] Ex AIC-1Yaquinto Dir at 4.
[68] Ex AIC-1 Yaquinto Dir at 5.

Terms and Conditions of the Settlement Agreement

Section I of the Settlement Agreement contains the Recitals which identify the parties and describe the settlement process. This Section of the Settlement Agreement identifies the following benefits:

- Even though TEP's current rates have been in effect for almost five years, the first year bill impact for a residential customer using the annual average of 767 kilowatt-hour ("kWh") per month, is less than $3.00 per month (including the PPFAC and DSM surcharge, but not including the REST surcharge, taxes or assessments);
- Small commercial customers receive a lower percentage rate impact than the other customer classes;
- Bill assistance continues for low income customers;
- A proposal that provides rate treatment for investments in energy efficiency in a manner similar to rate treatment for investments in other resources and that reduces the rate impact to the customer;
- An ECA mechanism that allows recovery, with a cap, of government-mandated environmental compliance costs in a manner that smoothes the rate impact of such compliance;
- A narrowly-tailored LFCR mechanism that supports EE and DG at any level or pace set by the Commission; and
- A fixed cost LFCR rate option for residential customers preferring to pay a specified charge for lost fixed costs rather than the variable LFCR.

The Signatories to the Settlement Agreement ask the Commission to find that the terms and conditions of the Settlement Agreement are just and reasonable and in the public interest; and to approve the Settlement so that the rates contained therein can become effective on July 1, 2013.

Section II of the Settlement Agreement describes the Rate Increase. The Settlement Agreement provides that TEP receives a non-fuel base rate increase of $76,194,257 over adjusted test year retail revenues,[69] reflecting a total non-fuel revenue requirement of $659,724,574.[70] In addition, TEP's base fuel rates are set to recover a total of $300,252,951, which is an annual increase of $31,599,730 over the amount recovered through current base rates.[71] Furthermore, the PPFAC rate will be reset on the effective date of the new rates, which will reduce the present annual recovery of fuel costs by $52,750,597.[72] The Settlement Agreement provides that TEP's jurisdictional FVRB is $2,268,199,253, which is the average of the OCRB of $1,507,062,648, and the RCND rate base of $3,029,335,858.[73] The Company's total adjusted test year revenue requirement is set at $959,977,525.[74]

Section III of the Settlement Agreement discusses the bill impact. Under the rates provided under the Settlement Agreement, a residential customer using the annual average of 767 kWh per month, will see a monthly increase of less than $3.00, on account of the base rate increase, the reduction in the PPFAC rate and reduction in the DSM surcharge rate.[75] Attachment "B" to the Settlement Agreement shows the percentage revenue allocation among the customer classes. Under the terms of the Settlement Agreement, the portion of the overall revenue requirement to be recovered through base rates ($921,195,613), is an increase of 13.3 percent over test year revenues. The Residential Class receives a 13.3 percent increase; the Small Commercial Class receives an increase of 12.3 percent; and the Water Pumping Class, Large Commercial, Large Light and Power, and Lighting Classes all receive an increase of 14.1 percent.[76]

Section IV of the Settlement Agreement discusses the Cost of Capital. The Settlement Agreement adopts TEP's actual test year capital structure comprised of 55.97 percent long-term debt, 0.53 percent short term debt and 43.5 percent common equity.[77] The Settlement Agreement adopts a

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[69] TEP initially requested a non-fuel base rate increase of $127,760,000.
[70] Settlement Agreement § 2.1.
[71] Settlement Agreement § 2.2.
[72] Under the terms of TEP's existing PPFAC, the PPFAC would have been re-set effective April 1, 2013, and would have reduced the PPFAC rate from $0.007696 to negative $0.001388/kWh . In Docket Nos. E-01933A-05-0650 and E-1933A-07-0402, TEP filed a Notice of Filing Updated PPFAC Information and Motion to Defer Effective Date of PPFAC Rate Adjustment.
[73] Settlement Agreement at § 2.3.
[74] Settlement Agreement at §2.3.
[75] Settlement Agreement at § 3.1.
[76] Attachment "B" to Settlement Agreement.
[77] Settlement Agreement at § 4.1.

return on common equity of 10.0 percent, an embedded cost of long-term debt of 5.18 percent and a cost of short-term debt of 1.42 percent.[78] The FVROR under the agreement is 5.05 percent, which includes a rate of return on the fair value increment of rate base of 0.68 percent.[79] The Agreement provides that the cost of capital, FVRB, FVROR and the revenue requirement are made for purposes of settlement only and should not be construed as admissions against interest or waivers of litigation positions related to other or future cases.

Section V of the Settlement Agreement concerns Depreciation/Amortization rates. The Settlement Agreement adopts the depreciation and amortization rates proposed by TEP and contained in the pre-filed Direct Testimony of Dr. Ron White.[80]

Section VI addresses the Purchased Power and Fuel Adjustment Clause. The Settlement sets the average retail base fuel rate at $0.032335 per kWh, which reflects total annual fuel and purchased power costs of $300,252,951.[81] The base rate does not include the PPFAC rate established in the Settlement Agreement which includes a one-time $3 million credit related to previous sulfur credits and a $9.7 million deferral of costs related to the San Juan Thermal Event.[82] On the effective date of new rates, the Settlement Agreement provides for the PPFAC rate to be re-set at negative $0.001388 per kWh (i.e., a credit on the customer's bill).

The Plan of Administration for TEP's PPFAC is set forth in Attachment "C" to the Settlement Agreement. The PPFAC is modified under the Settlement Agreement to include the recovery of the following costs/credits: broker fees, lime costs, sulfur credits, and 100 percent of proceeds from the sale of SO2 allowances. The Signatories to the Settlement Agreement believe that it is in the public interest to defer the reset of TEP's PPFAC from April 1, 2013, to July 1, 2013, the presumed effective date of the rates approved in this docket.[83]

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[78] Settlement Agreement at § 4.2.
[79] Settlement Agreement at § 4.3.
[80] Ex TEP-1; Settlement Agreement at § 5.1.
[81] Settlement Agreement at § 6.1.
[82] There was a fire at the San Juan mine in September 2011. The treatment of the costs associated with the fire is discussed in § 14.1 of the Settlement Agreement.
[83] Settlement Agreement at § 6.3.

Section VII of the Settlement Agreement addresses TEP's EERP. Under the terms of the Settlement Agreement, TEP will implement an EERP as proposed in Staff's Direct Testimony.[84] Under the EERP, TEP will invest in cost-effective energy efficiency programs that have been approved by the Commission, and after providing documentation that the programs have been effective, TEP will be allowed to recover the costs of its investments, including the rate of return established in this case, through its existing DSM adjustor mechanism.[85] TEP's annual EE investments under the EERP will be amortized over five years.[86]

TEP agreed to resume funding EE programs that the Commission previously approved beginning March 1, 2013, and will request recovery of those costs through the EERP. The pro-rata budget for the period July 1, 2013 through December 31, 2013 is approximately $12 million, which is based on the budget recommended by Staff in TEP's 2011-2012 Energy Efficiency Implementation Plan filed in Docket No. E-01933A-11-0055.[87]

The DSMS will be assessed on a per kWh basis for residential customers and on a percentage of bill basis for non-residential customers. The DSMS for residential customers will be reset from $0.001249 per kWh to $0.000443 per kWh upon the effective date for new rates.[88] Customers who can demonstrate an active DSM program and whose single site usage is 25 MW or greater, may file a petition with the Commission for an exemption from the DSM adjustor, and if approved, will be removed from the Energy Efficiency Standard denominator.[89]

The Settlement Agreement provides that "[n]othing in the [EE] Plan is intended to bind the Commission to any specific EE policy or standard, but merely sets up the method of recovery for investments in EE for any EE policy or standard established by the Commission."[90]

Section VIII of the Settlement Agreement establishes a Lost Fixed Cost Recovery mechanism, a Fixed Residential Rate Option, and a Large Customer Exclusion for recovery of lost fixed costs that result from approved EE programs. The Settlement Agreement recognizes that under TEP's

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[84] Settlement Agreement at § 7.1; Ex Staff-9 McGarry Dir.
[85] The Plan of Administration for the EE Plan is attached to the Settlement as Attachment "D"; Tr. at 193-97 (Olea).
[86] Settlement Agreement at § 7.2.
[87] Upon the effective date of the rates in this case, TEP will file a request to close Docket No. E-01933A-11-0055.
[88] Settlement Agreement at § 7.8.
[89] Settlement Agreement at § 7.6.
[90] Settlement Agreement at § 7.9.

volumetric rate design, the Company recovers a significant portion of its fixed costs of service through kWh sales, and that Commission rules related to EE and DG require TEP to sell fewer kWhs, which in turn, prevents the Company from being able to recover a portion of the fixed costs of service.[91] The Settlement adopts a LFCR mechanism, with a residential fixed rate option, to collect verified lost kWh sales attributable to Commission requirements regarding EE and DG.[92] The LFCR is intended to recover a portion of distribution and transmission costs associated with residential, commercial and industrial customers when sales levels are reduced by EE and DG and not to recover lost fixed costs attributable to generation and other potential factors, such as weather or general economic conditions. The LFCR has a 1 percent "year-over-year" cap based on total applicable TEP retail revenues.[93] Any amount in excess of the 1 percent cap will be deferred for collection as provided under the LFCR POA.[94] The amount of the cap will be evaluated in TEP's next rate case.

The LFCR mechanism will not apply to Large Light & Power, Water Pumping or Lighting customers as these customer classes pay their "fair share" of fixed costs through their monthly minimum and/or demand charge. Residential customers will have the option of electing a fixed monthly service charge in lieu of the LFCR which is determined based on kWh use. Initially, the fixed rate option is set at $2.50 for usage less than 2,000 kWh and $6.50 for usage of 2,000 kWh or more.[95]

The LFCR will recover the lost fixed costs on a calendar year basis from January 1, 2013, forward, with the first LFCR surcharge going into effect on July 1, 2014.[96] TEP has agreed to seek stakeholder input on the development of a customer outreach program to inform and educate customers about the LFCR.

Section IX of the Settlement Agreement establishes an ECA Surcharge. TEP will recover environmental compliance costs, subject to a cap of 0.25 percent of total TEP retail revenue. TEP will have to demonstrate that the environmental controls were government-mandated and represented a

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[91] Settlement Agreement at § 8.1.
[92] Settlement Agreement at § 8.2.
[93] I.e., average bills for customers shall not increase by more than 1 percent. Settlement Agreement at § 8.4.
[94] The LFCR POA is Attachment "F" to the Settlement Agreement.
[95] Settlement Agreement at § 8.6 and Attachment "E".
[96] Settlement Agreement at § 8.8.

reasonable and prudent option available to TEP at the time sufficient to meet the environmental requirement.[97]

Section X of the Settlement Agreement addresses SGS Unit 1. Under this provision TEP will file a report with the Commission no later than July 31, 2014, addressing the status of the SGS lease agreements and the estimated change in TEP's non-fuel revenue requirement at the end of each primary lease term.[98]

By July 31, 2014, TEP will report on the details of any commitments to purchase, or otherwise retain capacity rights to, SGS Unit 1; any commitments to purchase replacement generating resources or purchased power agreements if TEP elects not to purchase SGS Unit 1; any commitments to purchase the SGS Coal Handling Facilities or extend the SGS Coal Handling Facilities lease term; and the estimated non-fuel revenue requirement associated with each of the commitments, including the proposed rate treatment of any remaining balance of SGS leasehold improvements. Depending on the contents of TEP's report, the Commission or any Signatory to the Settlement Agreement, may request TEP to explain why the Commission should not conduct a proceeding to have TEP's rates reduced.[99]

Under Section XI of the Settlement Agreement, TEP agrees to adopt Staff's proposed modifications to TEP's energy procurement program. The adopted modifications are set forth in Attachment "H" to the Settlement.[100]

Section XII of the Settlement Agreement provides that TEP will limit a typical Lifeline customer's increase to an amount that is generally reflective of the average monthly dollar increase of a standard R-01 customer. In addition, the PPFAC and DSM surcharges will apply to Lifeline customers, and currently frozen Lifeline rates will no longer be portable.[101] In lieu of using the annual interest from a $4.5 million LIFE Fund that TEP established in 1996 for the benefit of low income customers,[102] TEP will make an annual contribution to the Arizona Community Action Association

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[97] Settlement Agreement at § 9.1; The ECA POA is set forth in Attachment "G" to the Settlement Agreement.
[98] Settlement Agreement at § 10.1.
[99] Settlement Agreement at § 10.2.
[100] Settlement Agreement at § 11.1.
[101] Settlement Agreement at § 12.2.
[102] See Decision No. 59594 (March 29, 1996); the Signatories agree that the LIFE Fund should be extinguished.

in the amount of $150,000 to fund low-income utility bill assistance programs, commencing September 1, 2013.

Section XIII of the Settlement Agreement provides that before requesting any rate recovery from the Commission for the costs related to the development of the transmission line between Tucson and Nogales, TEP agrees to seek recovery of these costs from the Federal Energy Regulatory Commission ("FERC"). No party is precluded from challenging the inclusion of these costs in rates either before FERC or the Commission.[103]

Section XIV of the Settlement Agreement addresses accounting for the direct costs related to a fire at the San Juan mine in 2011. Pursuant to this section, TEP will maintain a separate accounting of all direct costs related to the fire, and the recovery of these costs will be deferred until the insurance settlement has been completed. The deferred costs are estimated to be $9.7 million. The Agreement provides that TEP will be eligible to put all costs in excess of the insurance recovery through the PPFAC subject to the standard prudence determination.[104]

Section XV of the Settlement Agreement addresses rate design. The new rates are set forth in Attachment "J" to the Settlement Agreement. In addition, the Settlement Agreement provides that the rate design portion of the docket shall remain open until July 1, 2014, to allow for the possible adjustment of specific tariffs to correct unanticipated customer rate impacts that are inconsistent with the public interest.

Section XVI of the Settlement Agreement adopts TEP's revised Rules and Regulations.

Section XVII of the Settlement Agreement eliminates TEP's GreenWatts tariff and adopts the Statement of Charges set forth in Attachment "K" of the Agreement.

Section XVIII of the Settlement Agreement addresses TEP's commitment to quality of service. TEP agrees to continue to evaluate the Company's reliability on the basis of the distribution indices being maintained at current levels, and to initiate a study within 180 days of the effective date of the approval of the Settlement Agreement to examine potential loss reductions and the costs to convert 4.1 kV circuits to 13.8 kV. TEP agrees to meet with Staff to address potentially increasing

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[103] Settlement Agreement at § 13.1.
[104] Settlement Agreement at § 14.1.

the pace of upgrading critical circuits; establishing a routine of periodic load-flow analysis of its system and equipping feeder circuits with meters or other equipment so that power information can be relayed to Energy Management Service ("EMS") through SCADA to determine losses on a circuit-by-circuit basis.

Section XIX of the Settlement Agreement provides for the elimination of certain compliance reports. TEP will continue to file the reporting requirements under the Commission's Retail Electric Competition Rules (A.A.C. R14-2-1601) et seq. and the Cost Containment Report pursuant to Decision No. 59094 (March 29, 1996). Attachment "L" to the Settlement Agreement: 1) eliminates the requirement in Decision No. 56526 (June 22, 1998) that TEP file monthly reports on unit costs and unit performance for each generating unit or other sources of energy; 2) eliminates the requirements in Decision No. 57029 (July 18, 1990) and Decision No. 57924 (July 2, 1990) to file annual reports on an agreement with Liquide Air; and 3) modifies the Lifeline Discount Tariff reporting requirements from Decision No. 56659 (October 24, 1989)(as modified in Decision Nos. 56781, 56819 and 57370) to now require TEP to submit information on the total number of customers receiving a discount; the total number of kWh consumed by customers receiving a discount; and the total dollar amount of discounts provided.

Section XX of the Settlement Agreement is entitled "Additional Settlement Provisions" and includes miscellaneous actions to which TEP has agreed. In the next rate case, TEP will propose to treat the approximate 12,000 square feet of retail space in its new headquarters building in a similar manner as it is in this case, which assumes a rent equivalent to $20.83/square foot.[105] Within 60 days of the final decision in this case, TEP has agreed to file a request to open a generic docket to address the appropriate accounting treatment of Net Operating Losses ("NOLs") in future rate cases.[106] In recognition of RUCO's concerns about excess depreciation, TEP agrees that in any filing relating to the early retirement of a production asset, TEP will propose that any then-existing excess depreciation reserve will be applied to the unrecovered book value of the retiring assets and that TEP will propose in the next rate case that the remaining excess depreciation, if any, will be made over 15

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[105] Settlement Agreement at § 20.1; Attachment A.
[106] Settlement Agreement at § 20.2.

years.[107] TEP also agrees to meet with RUCO and Staff once a year over the next three years to discuss TEP's capital expenditures, planning horizons and related planning for the upcoming year.[108] TEP agrees to file by August 30, 2013, a proposed tariff for interruptible rates; and in its next rate case, TEP agrees to propose a rate for customers to take service at 138 kV or higher.[109]

Section XXI of the Settlement Agreement addresses the process for approving the Settlement Agreement, acknowledging that if the Commission fails to adopt all material terms, any or all Signatories to the Agreement may withdrawal from the Agreement.

Section XXII contains Miscellaneous Provisions, pertaining to positions taken in settlement and *inter alia*, recognizing that a Signatory's acceptance of a specific element of the Settlement Agreement shall not be considered as precedent for acceptance of that element in any other context.

Benefits of the Settlement Agreement as Identified by the Parties and Staff

TEP[110] argues that the Settlement Agreement provides real and significant benefits to TEP's customers, employees and shareholders. The Settlement proponents identify the following benefits of the Settlement Agreement:[111]

- A limited first year bill impact (less than $3.00 per month for a residential customer using an annual average of 767 kWh per month) despite the fact that TEP's current rates will have been in effect for almost five years by the time the new rates go into effect;
- A deferral of the 2013 PPFAC reset in order to synchronize the change in the PPFAC rate with the change in rates approved in this docket;
- A lower percentage rate impact for small commercial customers than for other customer classes;
- Increased bill assistance for low income customers;

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[107] Settlement Agreement at § 20.3.
[108] Settlement Agreement at § 20.4.
[109] Settlement Agreement at §§ 20.5 and 20.6.
[110] Several Settlement Signatories, including IBEW Local 1116, Vote Solar, AECC, RUCO and Opower, joined in all or parts of TEP's Closing Brief.
[111] TEP Initial Post-hearing Brief at 1-2; Staff Opening Brief at 6.

- An EERP proposal that provides rate treatment for investments in energy efficiency in a manner similar to rate treatment for investments in other generation resources and that reduces the DSMS and the rate impact to the customer;
- Resumption of EE programs during the pendency of this rate case;
- An ECA mechanism (with a cap) that allows recovery of government-mandated environmental compliance costs in a manner that will smooth the rate impact of such compliance;
- A narrowly-tailored LFCR mechanism that supports EE, DMS and DG at any level or pace set by the Commission;
- A fixed cost LFCR rate option for residential customers preferring to pay a specified charge for lost fixed costs rather than the usage-based LFCR charge;
- Rate simplification ; and
- Clarifications to the Company's Rules and Regulations.

TEP asserts that the record established that the Company must make substantial investments in its system over the next five years, and that the rates in this case must be sufficient to allow TEP to attract the needed capital.[112]TEP urges that the Settlement Agreement be approved as expeditiously as possible to reap its benefits without delay.

Staff believes that the terms of the Settlement Agreement are just, reasonable, fair and in the public interest in that they *inter alia*: 1) establish just and reasonable rates for TEP's customers; 2) promote the convenience, comfort and safety and the preservation of the health of the employees and patrons of TEP; 3) resolve the issues arising from the docket; and 4) avoid unnecessary litigation expense and delay.[113]

As noted by Staff, only two parties voiced opposition to the Settlement Agreement, and that opposition was focused totally on the LFCR mechanism, as SWEEP and Sierra Club advocated for

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[112] TEP Initial Post-hearing Brief at 3-4.
[113] Staff Opening Brief at 5.

full revenue decoupling.[114] Even Mr. Schlegel for SWEEP testified that notwithstanding the absence of full revenue decoupling, "on balance . . .the settlement agreement is in the public interest."[115]

AIC asserts that while the economic collapse in 2008 nearly flattened customer usage, it did not chill TEP's need to make substantial capital improvements to maintain safe and reliable service or its need to increase operating and maintenance expenses to assure those service requirements were met.[116] AIC notes that since TEP's last rate case, its rate base increased by 50 percent or $500 million to $1.500 billion and that O&M costs have gone up about $29 million.[117] AIC believes that given the declining to flat sales, cost increases in all operational quadrants, plus the passage of so many years since the last rate increase, the fact that the Settlement Agreement holds the average residential bill impact to under $3.00 a month qualifies the Settlement as "remarkably consumer friendly."[118] However, AIC notes that the credit rating agencies view the Agreement as favorable as well.[119]

Settlement Process

TEP states that prior to the July 2, 2012 filing, it had several pre-filing meetings with Staff and RUCO and also invited interested parties and stakeholders to a meeting in Tucson where TEP summarized its forthcoming application. In addition, in the fall of 2012, TEP conducted four technical conferences on the various aspects of the application and had numerous discussions with various stakeholders.[120]TEP initiated, and Staff hosted, several settlement meetings with interested parties, at which parties could participate telephonically and have access to all documents discussed via TEP's electronic data room.[121]

TEP asserts that the record in this proceeding clearly establishes that the pre-filing meetings, technical conferences and settlement negotiations were open and transparent.[122] Furthermore, TEP states the open and transparent nature of the settlement negotiations served as a check and balance

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[114] Staff Opening Brief at 8.
[115] Tr. at 454, 457 (Schlegel)
[116] AIC Post-Hearing Brief at 2.
[117] AIC Post-Hearing Brief at 2; *citing* Application at 2.
[118] AIC Post-Hearing Brief at 2.
[119] AIC Post-Hearing Brief at 3.
[120] TEP Initial Post-Hearing Brief at 2-3, *citing* Ex TEP-2 Hutchens Settlement Dir at 6.
[121] TEP Initial Post-Hearing Brief at 3 *citing* Ex TEP-2 Hutchens Settlement Dir at 6.
[122] TEP Initial Post-Hearing Brief at 2.

that all interested parties had an opportunity to participate and be heard on the terms and conditions of the Settlement Agreement, and to ensure that the final Settlement Agreement is balanced, fair, just and reasonable and in the public interest.

Staff states the fact that eighteen parties representing significantly divergent interests were able to reach an accord in a contracted three week period, is testament to their dedication, good faith efforts and cooperation.[123] Staff notes that during negotiations, each participant was given a chance to advance its position and each of the Signatories compromised to reach agreement on all of the issues and in furtherance of the public interest.[124]

AECC's witness Higgins testified that the main strength of the Settlement Agreement is that it resolves a long list of concerns and issues in a comprehensive way that is fair to the customers and reasonable for the utility.[125]

The Rate Increase

TEP notes that the Settlement Agreement's non-fuel base rate increase of $76.2 million is significantly less than the $127.7 million increase that TEP had originally requested, and falls within Staff's initially recommended range for a base rate increase of between $75.4 and $84.0 million, and is similar to AECC's initial recommended increase of no more than $83 million.[126]

TEP states that the agreed revenue requirement, along with the other provisions of the Agreement, will allow TEP to: 1) maintain safe and reliable service throughout its service area; 2) comply with new environmental regulations; 3) build necessary infrastructure; and 4) have a reasonable opportunity to earn its Commission-authorized rate of return.[127] In addition, TEP believes the Settlement Agreement will strengthen TEP's financial position and credit metrics, which could result in higher credit ratings, all of which will help TEP attract capital at reasonable terms and help to minimize future rate increases for ratepayers.

Staff states that TEP has agreed to the reduced non-fuel base rate increase and limited first-year bill impact for customer despite the fact that its current rates have been in effect for almost five

[123] Staff Opening Brief at 6-7.
[124] Staff Opening Brief at 7.
[125] Tr. at 265-66 (Higgins).
[126] TEP Initial Post-Hearing Brief at 4; Ex TEP-2 Hutchens Settlement Dir at 9-10; Tr. (Higgins) at 247.
[127] TEP Initial Post-hearing Brief at 5; Ex TEP-2 Hutchens Settlement Dir at 4.

years.[128] Staff notes that TEP believes that the non-fuel revenue is critical to TEP to continue the positive momentum of the 2008 Settlement and allow the Company to attract capital on favorable terms.[129]

Bill Impact

As a result of the PPFAC rate re-set, which is a decrease due to the one-time sulfur credit and deferral of costs associated with the San Juan Mine fire, and the reduction in the DSMS under the proposed EERP, the monthly bill for a residential customer under the R-1 Tariff using the annual average of 767 kWh per month will increase less than $3.00. TEP believes that given that base rates have not increased in almost five years, the offset afforded by the lower PPFAC and DSMS is an "elegant" means to reduce the initial impact on the customer.[130]

TEP asserts that the revenue allocation under the Settlement Agreement somewhat mitigates the rate impact on residential and small business customers.[131] Mr. Dukes' testimony indicated that the Customer Class Cost of Service Study ("CCCSS") showed that under current rates, the small general service class contributes a greater return than other classes.[132] The Settlement Agreement allocates the small commercial class a slightly smaller revenue increase than the other customer classes. TEP states that the residential customer class was allocated a base revenue increase that equaled the aggregate percentage increase in order to keep bill impacts reasonable on that class, particularly for the low-income customers. As a result of the treatment for the residential and small commercial customer classes, the percent increase allocated to the other customer classes (large commercial, water pumping, lighting and large light and power) is slightly higher than the aggregate increase.[133] TEP argues that the revenue allocation under the Settlement Agreement is equitable, while gradually moving towards matching customer classes to their actual costs.[134]

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[128] Staff Opening Brief at 10.
[129] Staff Opening Brief at 10; Ex TEP-2 Hutchens Settlement Dir. at 10.
[130] Tr. at 247 (Higgins).
[131] In the aggregate the base rate revenue change averages 13.3 percent compared to test year base rates, but this percentage change does not take into account the $52,751 million reduction in fuel rates resulting from the reset of the PPFAC. When that change is included, the aggregate increase in fuel and non-fuel revenues is 2.6 percent. Ex TEP-4 Dukes Settlement Dir at 4.
[132] Ex TEP-4 Dukes Settlement Dir at 4.
[133] Settlement Agreement at Attachment B.
[134] TEP Initial Post-Hearing Brief at 6.

Cost of Capital

Settlement Agreement proponents note that the Settlement Agreement reconciles vastly disparate positions of the parties on the cost of capital.[135]The agreed ROE of 10.0 percent matches the 10.0 percent originally proposed by RUCO, and is lower than the 10.75 percent originally requested by TEP. The FVROR of 5.05 percent is lower than the 5.64 percent approved in TEP's last rate case, and is due primarily to TEP being able to lower its cost of debt in recent years. The Fair Value Increment of 0.68 percent, is lower than the 1.0 percent used in the APS Settlement Agreement adopted in Decision No. 73183 (May 24, 2012) and for UNS Gas, Inc. ("UNS Gas") in Decision No. 73142 (May 1, 2012).[136] Staff notes that the Settlement Agreement adopts TEP's actual test year capital structure as initially recommended by Staff and AECC rather than the hypothetical structure proposed by the Company.[137] Mr. Higgins testified that the Company's proposed hypothetical capital structure would have "unduly increased its revenue requirement."[138]

PPFAC

TEP states that normally in rate cases, the PPFAC rate would be reset to zero, but that in this case, the PPFAC rate is being set at negative $0.001388 per kWh due to a one-time $3 million credit related to previous sulfur credits and a $9.7 million deferral of costs related to the San Juan Thermal Event. With the new base fuel rate being set at $0.032335 per kWh, the overall fuel rate will be $0.030947 per kWh, which is lower than the current overall fuel rate of $0.036592 per kWh.[139] Thus, TEP notes, the overall fuel rate decrease will offset the non-fuel base rate increase to a certain extent.[140] In addition, TEP notes that changes to the PPFAC will allow the inclusion of certain costs and credits, including lime costs, broker fees, sulfur credits and 100 percent of revenues from the sale of SO2 emission allowances.

The Settlement Agreement Signatories believe that it is in the public interest that the PPFAC rate not be reset until the effective date of the new rates in order to: 1) help mitigate the impact of the

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[135] Staff Opening Brief at 11.
[136] TEP Initial Post-hearing Brief at 7.
[137] Staff Opening Brief at 10.
[138] Ex AECC-3 Higgins Settlement Dir at 5.
[139] $0.028896 per kWh base fuel rate + $0.007696 PPFAC rate.
[140] TEP Initial Post-Hearing Brief at 8.

new rates by reducing the True-Up Component portion of the new 2013-2014 PPFAC rate (which would otherwise have a significant under-collected bank balance as of April 1, 2013); 2) avoid "yo-yoing" of rates; and 3) reduce customer confusion.[141]

EE Resource Plan

The EERP included in the Settlement Agreement is based on proposals made by both Staff and TEP in their direct testimony.[142] Currently, TEP recovers EE/DSM program costs, including a performance incentive, from customers through the DSMS over a one year period and expenses the costs of implementing the programs in that same year. According to TEP, the EERP allows TEP to invest in cost-effective EE/DSM programs and recover those costs, including a return on its investment, but not a performance incentive, from customers through Commission-approved DSMS over a five year period. The EERP POA provides that TEP will recover its annual EE amortization expense and a return on the EE investment based on the WACC, and the Company will only be allowed to recover the costs of its EE/DSM investments if it can demonstrate that certain performance metrics have been met.[143] As is the current practice, TEP will file annual implementation plans and budgets with the Commission for review and approval, and TEP will be allowed to invest in those EE/DSM programs and measures as approved by the Commission.

By collecting the authorized costs over a five-year period (instead of the current one year period), TEP claims that the rate impacts on TEP's customers are less and smoother and better synchronized with the costs of the EE/DSM programs, and will help reduce any "intergenerational" cost shifting.[144]

TEP asserts that the two significant differences of the proposed EERP from the current practice—i.e. putting recovery at risk subject to meeting performance metrics, and colleting the costs over five years—provide better customer benefits. TEP states that no party to the docket, including SWEEP, opposed the EERP, and asserts that the EERP is a reasonable approach to EE cost recovery

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[141] TEP Initial Post-Hearing Brief at 8; Staff Opening Brief at 12; Tr. at 82-3 (Hutchens).

[142] Ex Staff-15 Olea Settlement Dir at 9.

[143] If the investments do not provide results above the minimum expected energy savings and below a targeted price per kwh, then TEP will not be allowed to recover the costs related to those EE/DSM programs. The initial minimum annual portfolio level savings is 84,024,000 kWhs and the maximum portfolio level costs is $0.02208 per kWh. *See* Settlement Agreement Attachment D at 6.C.

[144] TEP Initial Post-Hearing Brief at 9; Tr. (Higgins) at 251-52.

that spreads the impact on customers over time rather than having a sharp increase in the DSM surcharge.[145]

The EERP does not dictate which EE/DSM programs and budgets the Commission may approve.[146]TEP states that the proposed EERP does not set or bind the Commission to any particular policy or standard regarding EE, but is rather merely another way to fund and collect the costs of EE/DSM programs. TEP argues that it is imperative that the Commission approve an EE Implementation Plan and the EERP contained in the Settlement Agreement resolves this issue.[147] TEP asserts that it is apparent from the public comment received in Docket E-01933A-11-0055 as well as in this docket, that EE is widely supported in TEP's service territory.

TEP states that although it supports the EERP as contained in the Settlement Agreement, TEP understands that EE is a policy issue for the Commission. In the event that the EERP in the Settlement Agreement is not approved, TEP asserts that there remains the need to resolve in this docket both the desire of TEP's customers to have TEP reinstate and expand its EE/DSM programs; and the impacts that EE/DSM programs have on TEP.[148] If the Commission does not approve the EERP, TEP proposed an alternative option to the EERP ("Existing EE Rule Option").[149] TEP states that although not the preferred and agreed-upon method to fund EE/DSM, approval of the Existing EE Rule Option would resolve the issues and allow EE to move forward.[150]

Staff believes that EE is one of the cheapest resources and that it is in the public interest to treat investments in such programs similar to other typical generation resources.[151] Staff asserts that the Settlement Agreement is structured to give the Commission more flexibility between rate cases to

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[145] TEP Initial Post-Hearing Brief at 10.
[146] TEP Initial Post-Hearing Brief at 19.
[147] TEP Initial Post-Hearing Brief at 19.
[148] TEP Initial Post-Hearing Brief at 19.
[149] Ex TEP-2 Hutchens Settlement Dir at 17-21 and Ex DGH-2 thereto; Ex TEP-11 (revised version of Ex DGH-2)(late-filed).
[150] The Existing EE Rule Option is described in DGH-2, attached to Mr. Hutchens' testimony and revised in Ex TEP-11. AECC's witness Higgins believed that the Existing EE Rules Option as originally described by Mr. Hutchens required some tinkering. For example, Mr. Higgins noted that DGH-2 did not reference that the DSMS applied to the small commercial class would be on a percentage of bill basis. Tr. at 259 (Higgins). Ex TEP-11, the revised description of the Existing EE Rule Option corrected the oversight.
[151] Staff Opening Brief at 13; Ex S-15 Olea Settlement Dir at 11.

make policy determinations with respect to EE or DG, and that the Settlement in no way limits the Commission's authority to decide what to do with respect to EE or the EEE Rules.[152]

Interest in TEP's EERP and how it might affect its members was one of the motivating factors for SAHBA to intervene in this matter.[153] The fact that TEP agreed to re-implement its EE spending on March 1, 2013, is an important feature of the Settlement Agreement for SAHBA.[154]SAHBA members participate in those EE programs and are optimistic that the programs will provide an added incentive to SAHBA's members to construct energy efficient homes that exceed building code requirements. Benefits of EE to SAHBA include the ability to market the advantages of an energy efficient home which gives them an advantage during a critical time in the housing recovery, in addition to the fact that these new qualifying homes will conserve energy and lower energy bills.[155]

As one of TEP's contractors for EE services, EnerNOC intervened in this proceeding because of its interest in TEP's EERP. EnerNOC provides commercial and industrial load curtailment services pursuant to TEP's DLC Program. EnerNOC states that the DLC Program provides benefits to TEP, it customers (both participants and non-participants) by: 1) giving TEP the ability to call upon the program when demand is approaching peak conditions; 2) giving TEP the flexibility to call upon its demand resources as an alternative to procuring incremental supplies in the wholesale market or to avoid dispatching a less efficient generator; and 3) by providing support when unexpected transmission or generation outages occur to provide system reliability support.[156] According to EnerNOC, when DLC Program participants reduce their demand they reduce stress or congestion on the distribution or transmission system; obviate the need for higher-priced capacity or energy resources; and contribute to the Company's reserve margin for planning purposes.[157] The DLC Program which allows customers to control a portion of their energy costs and receive a payment for that modified behavior provides benefits to the reliability and cost of operating the electric system, to the benefit of all customers.[158]

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[152] Staff Opening Brief at 8 and 13; Settlement Agreement at §§ 7.9 and 8.2
[153] SAHBA initial Brief at 2-3.
[154] SAHBA Initial Brief at 4.
[155] SAHBA Initial Brief at 4-5.
[156] EnerNOC Initial Brief at 2.
[157] EnerNOC Initial Brief at 2.
[158] EnerNOC Initial Brief at 3.

EnerNOC reports that the delay in approving TEP's 2011-2012 EE Implementation Plan was disruptive and EnerNOC lost the opportunity to realize the full value of its contract with TEP. In addition, the suspension of EE programing created an environment of uncertainty as to the Commission's support for the EE Standard.[159] According to EnerNOC, it halted investment in Arizona and created uncertainty among consumers as to whether they can rely on the programs. EnerNOC asserts that if programs are going to start and stop or come and go, customers will not make the behavioral changes necessary to make EE effective because there is not a perceived regulatory commitment to the continuation of the program.[160] EnerNOC argues that without EE, the only direction for the cost of providing service is up because more resources will need to be acquired to accommodate growing demand.[161]

LFCR

TEP and Staff assert that the LFCR is needed because TEP's current rate structure is designed to recover the Company's authorized revenue requirement primarily through usage-based kWh sales.[162] The volumetric rate charged for those sales is calculated based on the system-wide usage, based largely on the sales volumes experienced during the test year.[163] However, as TEP notes, a majority of the costs included in TEP's revenue requirement do not vary with kWh sales, but are fixed. Thus, under the current rate structure, when kWh sales decline as a result of EE/DSM programs and DG systems, TEP does not recover the fixed distribution and transmission costs that are embedded in its volumetric-based rates, and it does not have an opportunity to recover certain costs or achieve its Commission-authorized rate of return. AIC agrees that the LFCR is needed to help stabilize earnings in the face of unrecovered fixed costs caused by reduced sales attributed to EE and DG efforts and that it is similar to the one adopted for APS.[164]

TEP states that the LFCR in the Settlement Agreement is narrowly tailored to collect distribution and transmission service costs that would have been recovered through usage lost to

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[159] EnerNOC Initial Brief at 4.
[160] EnerNOC Initial Brief at 4.
[161] EnerNOC Initial Brief at 4.
[162] Staff Opening Brief at 14; TEP Initial Post-Hearing Brief at 11.
[163] Ex TEP-2 Hutchens Settlement Dir at 14.
[164] AIC Post-Hearing Brief at 5.

EE/DSM programs and DG systems and is not intended to recover lost fixed costs attributable to other factors, such as generation, weather or general economic conditions.[165] TEP states the LFCR will have a 1 percent year-over-year cap based on total applicable TEP retail revenues and is similar to the LFCR the Commission approved for APS and UNS Gas.[166] AIC states that both the Southwest Gas decoupler mechanism and the LFCR mechanism for APS have been functioning without any administrative or recovery problems.[167] In addition, Staff notes that TEP will implement an extensive customer education and outreach program commencing in 2014 to help customers understand the LFCR and options.[168]

TEP states that the LFCR proposed in the Settlement Agreement is narrower in scope than originally proposed, and the ability to craft a reasonable residential fixed charge option, aka the "opt-out" rate, allowed the Signatories to reach consensus on the LFCR. TEP states that the LFCR included in the Settlement Agreement reflects the desire of the Signatories (including Staff, RUCO and others) to have a more limited and targeted mechanism than full revenue decoupling and is consistent with current Commission decisions.

Staff states that although SWEEP and Sierra Club have expressed their opposition to the Settlement Agreement's LFCR as "partial" opposition, it is important to recognize that the proposed Settlement Agreement is a global resolution of the issues in dispute, and that changing a material term could endanger the viability of the Agreement. Staff argues that because SWEEP and Sierra Club did not provide specific details of how their proposed modifications would be implemented, their recommendations should be rejected.[169]

Staff argues that the LFCR is preferable to full revenue decoupling in the context of this case because it is narrowly crafted and avoids delay.[170] Staff's witness Solganick identified several adverse characteristics of full decoupling that are avoided under the LFCR. First, decoupling could result in "pancaking" increases which happen when a period of mild weather and reduced demand

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[165] TEP Initial Post-Hearing Brief at 10; Ex TEP-2 Hutchens Settlement Dir at 13.
[166] Decision No. 73183 and Decision No. 73142.
[167] AIC Post-Hearing Brief at 6. AIC believes any unanticipated problems with the mechanism in this case should be dealt with pursuant to A.R.S. § 40-252 and re-opening the docket.
[168] Staff Opening Brief at 14.
[169] Staff Opening Brief at 18.
[170] Staff Opening Brief at 20-21.

that would generate a surcharge is followed by a period of adverse weather, which would have customers paying higher bills for both their weather-driven consumption plus the surcharge from the previous period.[171] Second, Solganick described how full decoupling can give rise to a scenario where a utility benefits from prolonged outage events.[172] Finally, according to Solganick, full decoupling reduces the risks a utility faces, which could lead to a host of contentious questions of how much and when to make adjustments to the return on equity.[173]

Staff argues that the record in this matter does not contain sufficient detail to craft a reasonable full decoupling mechanism. Staff acknowledges that there may be ways to avoid the pitfalls of full decoupling with well-designed regulatory devises, but the devil is in the details, and the decoupling proponents have not supplied the requisite details.[174] Staff notes that SWEEP acknowledges that it would be the Company's responsibility to propose a decoupling mechanism, which would then be subject to comment and refinement from input from interested parties, but that process has not occurred in this case because the Company is proposing an LFCR instead of full decoupling. Staff asserts that even SWEEP admits that the LFCR is better than the status quo.[175]

AECC also prefers the LFCR to full revenue decoupling.[176] Mr. Higgins recalls how full revenue decoupling was strongly opposed by RUCO, AECC and AARP during the APS rate case, and he believes that TEP wisely proposed a mechanism for recovering lost fixed costs that is similar to the one adopted for APS. AECC opposes full revenue decoupling because it results in a change of rates for any change in average customer usages, whether due to weather, economy, or EE, and the more narrowly tailored LFCR is less likely to introduce unintended consequences or introduce extraneous factors that have nothing to do with disincentives for EE.[177]

ECA

The ECA is designed to allow TEP to recover a portion of the costs required to meet environmental compliance standards imposed by federal or other governmental agencies between rate

[171] Ex S-14 Solganick Settlement Dir at 16-17; Tr. at 501-02 (Solganick).
[172] Tr. at 502 (Solganick).
[173] Tr. at 330 (Dukes); 460 (Schlegel); 496 (Solganick).
[174] Staff Opening Brief at 21.
[175] Tr. at 358 (Schlegel).
[176] Tr at 256 (Higgins).
[177] Tr. at 254-55 (Higgins).

cases. The parties state that the ECA is similar to the mechanism that the Commission approved for APS.[178]

TEP asserts that the utility industry faces an ever-increasing number of rules creating more stringent environmental standards that will require the Company to invest an "unprecedented" amount of capital in its generation resource portfolio over the next five years.[179] In general, these environmental standards seek to reduce the emissions of certain substances including: SO_2, nitrogen oxide, carbon dioxide, ozone, particulate matter, volatile organic compounds, mercury, coal ash, and other toxics and combustion residuals.[180]

TEP asserts that the ECA will provide additional cash flow to help TEP recover the costs of capital additions on a more timely basis and to support credit quality, which can lower financing costs.[181] TEP claims that more importantly, however, the ECA will moderate the impact on customers by avoiding the large rate increases that would result from deferring these costs to a future rate filing.[182] In addition, TEP states that the annual amount collected from customers through the ECA is capped at 0.25 percent of TEP's retail revenues, or approximately \$2.3 million.[183] TEP points out that the initial ECA will not appear on customers' bills prior to the first billing cycle in May 2014.

Staff asserts that implementing the ECA will benefit both customers and the Company, as customers will be protected from large rate increases due to the 0.25 percent cap, and potentially will enjoy the benefits of TEP's lower financing costs. [184] In addition, Staff asserts that customers will benefit from the enhanced environmental protections themselves.

AIC focused on the ECA as a particularly important feature of the Settlement Agreement as it provides a means to meet ever more costly environmental compliance obligations.[185] AIC notes that environmental cost adjustors such as the ECA are growing increasingly more common in Arizona

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[178] *See* Decision No. 73183.
[179] Ex TEP-2 Hutchens Settlement Dir at 12.
[180] Ex TEP-2 Hutchens Settlement Dir at 12-13.
[181] TEP Initial Post-Hearing Brief at 12.
[182] TEP Initial Post-Hearing Brief at 12.
[183] TEP Initial Post-Hearing Brief at 12.
[184] Staff Opening Brief at 15. Staff notes that the Settlement Agreement adopts the cap which was not included in TEP's original request. Ex AECC-3 Higgins Settlement Dir at 11.
[185] AIC Post-Hearing Brief at 4.

and across the Nation. AIC's witness Yaquinto testified that environmental adjustment clauses or rate riders have been authorized in 27 states for over 60 utility companies.[186] AIC believes that consumers will benefit from the 0.25 percent cap which will limit the amount of any future increase, and that the more timely recovery of the costs between rate cases will help smooth the future consumer rate increase impacts.[187]

AECC was opposed to the ECA as originally proposed because it was open-ended with respect to rate impacts. According to AECC, with the cap, the ECA will be a minor charge that gives some relief to TEP without imposing an onerous burden on customers.[188]

Although it did not sign the Settlement Agreement because it supports full revenue decoupling instead of the LFCR mechanism, Sierra Club believes that the ECA as contained in the Settlement Agreement is an improvement over the ECA as originally proposed by TEP.[189] Sierra Club states that the ECA as originally proposed would have made recovery of TEP's capital investments easier for TEP by shifting the risks of imprudent expenditures onto customers, as TEP would have been able to recover the costs of those capital expenditures without first subjecting its decision to a prudence review in a rate case.[190] As originally proposed, Sierra Club believes the ECA would have eliminated any incentive for TEP management to consider whether alternatives to major expenditures at aging coal facilities could provide a better value for ratepayers. Sierra Club states that with the proposed Settlement Agreement's cost cap, that risk is diminished, however, Sierra Club asserts that the ECA mechanism still allows TEP to shift some of its risk of recovery to customers.[191]

Springerville Generating Station Unit 1

TEP currently owns 14 percent of SGS Unit 1 and leases the remaining capacity. Under the lease TEP has an option to purchase the remaining capacity of SGS Unit 1 in 2015. The Settlement Agreement sets out the information that TEP will formally provide to the Commission regarding the status of SGS Unit 1. Staff states that the timing of the report and type of information required to be

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[186] Ex AIC-1 at 5-6.
[187] AIC Post-Hearing Brief at 4-5.
[188] Tr. at 267 (Higgins).
[189] Sierra Club Post-Hearing Brief at 2-3.
[190] Sierra Club Post-hearing Brief at 3.
[191] Sierra Club Post-Hearing Brief at 3.

submitted is intended to allow Staff and other interested parties to review TEP's proposal and bring the matter to the Commission's attention before the leases expire in January 2015.[192] Staff believes this is a benefit because it addresses Staff's concerns that if TEP ends up buying SGS for a good price, it could reduce costs and affect rates.[193]

Nogales Transmission Line

TEP had originally requested recovery of the costs of developing the 345 kV line between Tucson and Nogales in this rate case. Under the Settlement Agreement, TEP will first seek recovery of those costs from FERC before requesting recovery from the Commission.

TEP notes that this provision is not intended to guarantee that TEP will be able to recover through retail rates any costs that are not recovered through a FERC proceeding.[194]

San Juan Thermal Event

As a result of a fire at the San Juan coal mine, TEP incurred additional fuel costs to replace the coal it normally received from the mine. The fuel costs of the replacement coal would normally be passed through the PPFAC. In this case, some of the increased costs resulting from the fire may be covered by insurance. TEP has agreed to credit the PPFAC, and defer recovery of any uninsured additional fuel costs, until issues regarding the insurance coverage are settled.[195]

Rate Design

TEP and Staff assert that the Settlement Agreement contains a rate design that begins the process of simplifying and modernizing the Company's rate offerings, while aligning rates more closely with the CCOSS.[196] They assert that the TOU rates are simplified to make them less confusing and more appealing to customers by: 1) making the peak times consistent across all classes in recognition that the actual peak times on TEP's system do not vary by class; 2) eliminating the shoulder period for all non-frozen TOU rate classes; and 3) reducing the length of the peak period to

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[192] Staff Opening Brief at 16.
[193] Tr. at 200 (Olea).
[194] TEP Initial Post-Hearing Brief at 14; Ex TEP-2 Hutchens Settlement at 22.
[195] TEP Initial Post-Hearing Brief at 14; Ex TEP-2 Hutchens Settlement Dir at 23.
[196] TEP Initial Post-Hearing Brief at 14; Staff Opening Brief at 16; Ex S-14 Solganick Settlement Dir at 5-7 and 10-11; Ex TEP-4 Dukes Settlement Dir at 6.

increase the savings opportunities and encourage greater customer participation.[197]

For large customers with a demand charge, TEP notes that the Settlement Agreement adjusts the demand charges to better reflect the cost to serve, modifies the "ratchet" to be consistent across classes and adjusts the per-kWh or "energy" charge, which for some customers represents a decrease.[198] TEP asserts that all of the rate design changes lead to a more balanced and equitable rate impact on all customers while reducing the administrative burden and costs for the Company.[199]

The Signatories to the Settlement Agreement realize that the consolidation and simplification of rates may have unintended consequences, and thus, the Settlement Agreement leaves the docket open until July 1, 2014, for the purpose of adjusting specific tariffs to correct any unanticipated customer impacts that were not consistent with the public interest. Any such changes, however, must be revenue neutral.

Staff notes that SWEEP and Sierra Club have an issue with the proposed increase in the basic service charge for residential ratepayers because it is a charge that customers cannot affect by changing consumption patterns, and because they believe that it is not consistent with the principles of gradualism.[200] Staff argues that SWEEP's concern that the basic service charge is increasing as much as 40 percent is a misunderstanding of the issue of gradualism.[201] Staff agrees with TEP's witness Dukes that gradualism is not a concern in the absence of a rate shock issue. With a total bill impact in this case of less than $3.00 a month for the average residential user, Staff states that there is no issue of rate shock here.[202]

TEP and Staff also disagree with SWEEP's concerns relating to the allocation of fixed cost recovery through the basic service charge.[203] Staff asserts that TEP offered ample testimony that even with the increase in the basic service charge, a substantial percentage of the Company's fixed costs

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197 TEP Initial Post-Hearing Brief at 15; Staff Opening Brief at 16; Ex S-14 Solganick Settlement Dir at 7; Ex TEP-4 Dukes Settlement Dir at 6.
198 TEP Initial Post-Hearing Brief at 15; Staff Opening Brief at 16; Ex TEP-4 Dukes Settlement Dir at 6-7.
199 TEP Initial Post-Hearing Brief at 16.
200 Under the Settlement Agreement, the monthly service charge for Residential R-01 customers increases $3, from $7 to $10 per month. See Ex-SWEEP-3 Schlegel Settlement Dir at 14-18.
201 Staff Opening Brief at 22.
202 Staff Opening Brief at 22.
203 Staff Opening Brief at 23; TEP Initial Post-Hearing Brief at 21.

remain tied to volumetric sales.[204] TEP presented evidence that for the average residential customer, the monthly charge will cover only $10 of the estimated $55 of fixed costs.[205] TEP and Staff argue that even with the increase in the basic service charge, customers retain significant opportunity to save on their electric bills by engaging in EE.[206] Staff states that two ratepayer advocates participated in the Settlement Agreement and have agreed to the proposed increase in rates. Staff argues that in light of the ratepayer advocates' support for the proposed Settlement Agreement, SWEEP's and Sierra Club's concerns regarding the slight increase to the residential basic service charge are not supported by the record and should be rejected.[207]

SAWUA supports the Settlement Agreement because it includes revised language related to new Rate Schedule GS-43 that clarifies that SAWUA's members can utilize the tariff. From a cost allocation and rate design perspective, and an "Availability" and "Applicability" perspective, SAWUA concludes that TEP's new Rate Schedule GS-43 and Article XV (Rate Design) of the Settlement Agreement warrant SAWUA's support.[208]

Vote Solar intervened because of concerns regarding the cost recovery and rate design proposals that might affect current solar customers. Vote Solar recommends adopting the Settlement Agreement because it addresses concerns regarding the monthly customer charge, the increase in the demand ratchet and the LFCR in a manner that Vote Solar finds acceptable.[209]

Low-Income Programs

TEP currently has 17 different Lifeline (low-income) rates. TEP states that the Signatories, in particular Staff and Cynthia Zwick, spent many hours trying to devise low-income rates that would simplify the number of low income tariffs without unduly adversely impacting low-income customers.[210] TEP reports, however, that in order to keep the bill impacts for low-income customers at levels comparable to other residential customers, the parties were unable to consolidate the existing . . .

[204] Ex TEP-3 Hutchens Settlement Resp at 6; Tr. at 317-319 (Dukes).
[205] Ex TEP-8.
[206] Staff Opening Brief at 23; TEP Initial Post-Hearing Brief at 21.
[207] Staff Opening Brief at 24.
[208] SAWUA Initial Brief at 3-6.
[209] Vote Solar Post Hearing Brief at 1*citing* Ex Vote Solar-2 Gilliam Settlement Dir.
[210] TEP Initial Post-Hearing Brief at 13.

17 Lifeline rates. TEP argues that the approach taken by the Settlement Agreement will slowly modernize the Lifeline rates by means of the following key elements:

- All new low-income customers will have available one of the four standard Residential Service schedules. The total fixed rate discount will increase from $8.00 per month to $9.00 per month for these open Lifeline rates;
- The portability of all frozen Lifeline rates will be eliminated in order to gradually reduce the number of Lifeline rates;
- In order to mitigate the impact on the Lifeline customers, the Lifeline TOU rate schedules maintain the shoulder peak periods;
- Low-income customers will now be subject to the PPFAC rate and the DSMS; and
- TEP will provide $150,000 to fund low-income bill assistance programs.

TEP states that most low-income customers will see a monthly bill impact of between $2 and $3, including the anticipated changes to the PPFAC.

Other Provisions of the Settlement Agreement
Procurement
Rules and Regulations
GreenWatts Tariff
Quality of Service
Compliance
Addition Provisions

As part of its review of the rate application, Staff engaged the services of a consultant to audit TEP's PPFAC and review TEP's fuel procurement practices. TEP agreed to several modifications to its procurement program as recommended by Staff and set forth in Attachment H to the Settlement Agreement.

The changes to the Rules and Regulations are mostly in line with the changes that the Company proposed with its initial application. TEP states that most of the changes were "clean-up" in nature, intended to eliminate inconsistencies and ambiguities. TEP states that the more substantive changes were intended to clarify areas that led to customer inquiries or complaints.[211] Section XVII of the Settlement Agreement eliminates the GreenWatts Tariff. TEP explains that the GreenWatts

[211] Ex TEP-7 Lindy Sheehy Dir.

Tariff is no longer necessary because TEP has other similar programs in place.[212] Section XIX eliminates two reporting requirements from Orders issued in 1989 and 1990 which contain compliance requirements that are either moot or supplanted by subsequent orders, or no longer necessary.[213]

With respect to Section 20.1, TEP and Staff explain that the intent is to have TEP propose a similar treatment of the retail space in TEP's headquarters building in the next TEP general rate case as TEP proposed in this case, but is not intended to bind the Commission to that treatment in the next rate case.[214] Because the issue of how to treat NOLs in rate cases may become a more frequent issue as a result of bonus depreciation opportunities, Section 20.2 (in which TEP will request that a generic docket be opened) is intended as a means to obtain guidance from the Commission to assist parties in the future.[215] TEP states that Section 20.3 address RUCO's concerns about how quickly TEP would return excess depreciation reserves to ratepayers.[216] Section 20.4, in which TEP will meet with Staff and RUCO, provides a process for addressing RUCO's concerns about future distribution plant.

In addition to the foregoing, TEP states it will file a proposed tariff for interruptible rates by August 30, 2013, and will propose a rate for very large customers (those taking service at 138kVh or higher) in its next rate case.[217] AECC's witness testified that the practice nationwide is that customers who take service at transmission levels are not assigned the cost of the secondary or primary distribution system.[218] TEP also has agreed to file by August 30, 2013, two additional tariffs: 1) a revised Partial Requirements Service ("PRS") tariff and 2) a new "super-peak" TOU tariff.[219]

<u>Opposition to the Settlement Agreement</u>

<u>SWEEP's Opposition</u>

Even though SWEEP did not sign the Settlement Agreement, it expressed appreciation of the efforts of Mr. Olea and TEP in working through the many challenging issues.[220] SWEEP states that

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[212] TEP Initial Post-Hearing Brief at 17.
[213] TEP Initial Post-Hearing Brief at 17.
[214] TEP Initial Post-Hearing Brief at 18; Staff Opening Brief at 17.
[215] TEP Initial Post-Hearing Brief at 18; Tr. at 206 (Olea); Tr. at 211 (Quinn).
[216] Tr. at 261-62.
[217] TEP Initial Post-Hearing Brief at 18.
[218] Tr. at 261-62 (Higgins).
[219] Tr. at 314 (Dukes).
[220] SWEEP Post-Hearing Brief at 1.

although there is much to like in the proposed Settlement, SWEEP opposes it because, in SWEEP's opinion, the proposed LFCR mechanism inadequately reduces utility disincentives to EE and therefore results in fewer opportunities for customers to reduce their energy bill. Instead, SWEEP supports the implementation of full revenue decoupling, which it believes better aligns the utility's financial interest with the interests of its customers. In addition, SWEEP opposes the increase in the residential monthly basic service charges, which SWEEP believes will limit the ability of customers to reduce their utility bills.[221]

SWEEP supports the EE programs and cost-recovery provision in Section VII of the Settlement Agreement.[222] SWEEP argues that EE programs provide significant cost-effective benefits to customers, the economy, the electric system and the environment, including reductions in water use and air pollution.[223] SWEEP states that without EE, TEP would have a significant remaining resource requirement that it would need to meet by investing in other more costly energy resources which would result in higher costs for customers.[224] SWEEP believes that the EERP in the Settlement Agreement would restore cost-effective EE programs and ensure that TEP customers receive EE services to reduce their energy bills. SWEEP asserts that the EERP in the Settlement Agreement resolves the difficult situation TEP customers have experienced as a result of cuts and suspensions to TEP's existing EE programs in 2012.[225] SWEEP urges the Commission to act to approve funding and programs for EE in order that customers can start to receive the savings and benefits these programs provide.[226] SWEEP states that TEP's 2012 Integrated Resource Plan demonstrates a need for increased energy efficiency resources for TEP customers.

SWEEP states it supports EE program cost recovery using either the amortization method adopted in the Settlement Agreement or using annual expensing under the current method.[227] SWEEP

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[221] SWEEP Post-Hearing Brief at 2.
[222] SWEEP Post-Hearing Brief at 2.
[223] Ex SWEEP-1 Schlegel Dir at 4-5.
[224] SWEEP Post-Hearing Brief at 4, Ex SWEEP-3 Schlegel Settlement Dir at 5-12. According to SWEEP, TEP estimates its cost for energy efficiency over the 2012-2020 time horizon to be $23/MWh, with the next most affordable energy resource at $83/MWh. *See* TEP's October 31, 2012 Rate Case Technical Conference presentation on its EE Resource Plan, which corrected the cost of EE in TEP's 2012 Integrated Resource Plan. *See also* Ex SWEEP-3 Schlegel Settlement Dir at 9-10.
[225] Ex SWEEP-1 Schlegel Dir at 6-9.
[226] SWEEP Post-Hearing Brief at 3.
[227] SWEEP Post-Hearing Brief at 4.

clarified that the EERP under the Settlement Agreement that calls for the amortization of the EE program costs over a five-year period using a regulatory asset, is not the same thing as "ratebasing" or how TEP would recover an investment in a generation plant.[228] SWEEP asserts that under the EERP, TEP would not have a large or significant incentive to over-invest in EE and would not be receiving a financial windfall or a high return on its investment in EE.[229] SWEEP asserts that the EERP of the Settlement is not a major shift in EE or energy resource policy, and that nothing in the proposed cost recovery approach should cause TEP to seek a waiver from the Commission's EEE Rules or justify Commission approval of a waiver or exemption from the Rule.[230]

SWEEP argues, however, that the Settlement Agreement limits the Commission from fully exploring the policy options for better aligning the utility interest with the customer and public interests and for addressing financial disincentives to EE.[231] SWEEP argues that compared to the LFCR, full revenue decoupling is a superior option for addressing a utility's financial disincentives to EE. SWEEP asserts that full revenue decoupling is important not only for full, enthusiastic utility support of EE programs, but also to encourage activities that reduce energy bills that are not directly linked to the Company's portfolio of EE programs, such as utility support for building energy codes and appliance standards, broad energy education and marketing, state and local government energy conservation efforts and federal energy policies.[232] In addition, SWEEP asserts that full revenue decoupling allows for bill adjustments in either a positive and negative direction, resulting in either a credit (as sales increase) or a charge.[233] SWEEP notes that in contrast, the LFCR does not provide a credit when actual revenues are higher than forecasted. Thus, SWEEP believes the Settlement Agreement sends mixed signals and the LFCR does not adequately align TEP's financial incentives with the interests of customers.

SWEEP also argues that the proposal to increase the monthly service charge is not in the interest of customers, as the vast majority of residential customers would experience an increase

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[228] SWEEP Post-Hearing Brief at 5; Ex SWEEP-3 Schlegel Settlement Dir at 12-13.
[229] Ex SWEEP-3 Schlegel Settlement Dir at 13 and Tr. at 123 (Hutchens) and 183 (Olea).
[230] SWEEP Post-Hearing Brief at 9; Ex SWEEP-4 Schlegel Settlement Resp at 4-5.
[231] SWEEP Post-Hearing Brief at 5-6.
[232] Ex SWEEP-3 Schlegel Settlement Dir at 12-4; Ex SWEEP-1 Schlegel Dir at 16-17.
[233] SWEEP Post-Hearing Brief at 6.

greater than 40 percent.[234] SWEEP argues such a percentage increase is not gradualism and will limit the ability of customers to reduce their utility bill.[235] SWEEP states "customers who reduce their utility bills by increasing energy efficiency will still have to pay the entire $3 per month increase in the basic service charge – there is no way for customers to reduce or mitigate this rate increase."[236] According to SWEEP, a higher basic service charge also reduces the customer incentive to engage in energy efficiency opportunities because customers can affect only a smaller portion of their total utility bills. In addition, SWEEP asserts that monthly basic service charges have a tendency to fall disproportionately on smaller customers "who can often least afford them."[237] SWEEP is adamant that it does not "misunderstand" the issue of gradualism, and argues that an increase in the portion of the fixed bill of 40 percent is not gradual.[238]

Sierra Club

Sierra Club filed pre-Settlement testimony advocating rejection of the ECA, and continues to believe that the ECA is not in the best interest of customers, but because the revised ECA that is part of the Settlement Agreement is limited by a cap of 0.25 percent of TEP's total retail revenue, Sierra Club does not oppose this section of the Settlement Agreement.[239] Even though it does not oppose the ECA contained in the Settlement Agreement, Sierra Club continues to assert that sound utility practices require TEP to subject all of its capital expenditure decisions to a prudence review prior to allowing recovery of those costs, and that these ratemaking principles should apply regardless of whether the capital expenses exceed $400 million, or whether they are of a much smaller magnitude and fall within the proposed cost cap.[240]

Sierra Club explains that it did not sign the Settlement Agreement because it opposes the LFCR mechanism and the proposed increase to the basic monthly service charge. Sierra Club states that it substantially agrees with the testimony provided by SWEEP on the issue and advocates the

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[234] The rates contained in the Settlement Agreement proposed to increase the Residential basic service charge that currently ranges between $7.00-$8.00 per month, to $10.00-$11.50 per month.
[235] SWEEP Post-Hearing Brief at 6; Ex SWEEP-3 Schlegel Settlement Dir at 15; SWEEP Reply Brief at 1-2.
[236] SWEEP Post-Hearing Brief at 7.
[237] SWEEP Post-Hearing Brief at 7; Ex SWEEP-2 Schlegel Rate Design Dir at 3-4; Ex SWEEP-3 Schlegel Settlement Dir at 15.
[238] SWEEP Reply Brief at 7.
[239] Sierra Club Post-Hearing Brief at 2.
[240] Sierra Club Post-Hearing Brief at 4.

adoption of full revenue decoupling.[241] Sierra Club argues that the LFCR mechanism does much less for consumers than full revenue decoupling, as under full decoupling, customer rates can be adjusted up or down, while under the LFCR, customers get an automatic rate increase.[242]

Sierra Club argues that the Commission should strongly support EE as the least cost energy resource and that EE not only saves money for the individual customers who take advantage of the EE programs, but also saves money for all ratepayers by lowering the total revenue requirement compared to the alternative of investing in additional power plants. Sierra Club recommends that the Commission reject the proposed Settlement Agreement and substitute SWEEP's recommendation for full revenue decoupling in place of the LFCR.

ANALYSIS AND CONCLUSIONS

In the test year ending December 31, 2011, TEP provided service to approximately 426,062 customers in and around Tucson, in Pima County, as well as to Fort Huachuca in Cochise County, Arizona.

TEP's current rates were set in Decision No. 70628 (December 1, 2008) ("2008 Rate Case"), at which time the Commission adopted the 2008 Rate Case Settlement Agreement which included a moratorium on base rates until January 1, 2013.[243] In the 2008 Rate Case, TEP received a base rate increase, excluding the impact of the PPFAC, DSMS and REST, of $47.1 million, or 6 percent, and a total revenue increase of approximately $136.8 million. The Company's FVRB under the 2008 Settlement was $1.45 billion.[244]

Revenue Requirement, Base Rate Design and PPFAC

The current Settlement Agreement calls for an increase in nonfuel base rates of $76.1 million, an increase in base fuel rates of $31,599,730, and a reset of the PPFAC rate that will reduce the present annual recovery of fuel costs by $52,750,597. Not including the effect of the negative PPFAC, DSMS or REST, the new rates result in an overall revenue increase of $107,794,202 or

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[241] Sierra Club Post-Hearing Brief at 2 and 4.
[242] Sierra Club Post-Hearing Brief at 4.
[243] TEP could not file a rate case application sooner than June 30, 2012. Decision No. 70628 at 12.
[244] The 2008 Rate Case was the Company's first rate increase since 1996. *See* Decision No. 59594 (March 29, 1996). In Decision No. 62103 (November 30, 1999), the Commission approved a Settlement Agreement that provided for the commencement of retail competition in TEP's service territory and established unbundled rates, with a rate decrease of one percent in 1999, another rate decrease of one percent in 2000, and rate freeze until December 31, 2008.

approximately 13.3 percent over total adjusted test year revenues of $813,401,411.[245] The FVRB established in the Settlement Agreement is approximately $2.26 billion, which is about $800 million greater than in the 2008 Rate Case.

The settlement process involved many intervenors representing a myriad of interests, including residential consumers, low-income consumers, large commercial and industrial users, commercial interests, the solar industry, energy efficiency contractors, water providers, environmental interests, governmental agencies, employees and shareholders. The process was open and transparent and resulted in a Settlement that resolves, or provides a timeline for future resolution, all of the issues raised in this docket.

The benefits to ratepayers under the Settlement Agreement include a modest bill impact of less than $3.00 for residential customers despite the fact that TEP's current rates have been in effect for almost five years; a lower percentage rate impact for small commercial customers; continuing bill assistance for low income customers; redesigned TOU rates that increase the opportunities for savings; the re-enactment of an EE Program and a rate treatment for investments in EE that reduces the rate impact for the customer; a revised DSMS that ties recovery to performance and eliminates the performance incentives contained in the current DSMS; an ECA that allows recovery of government-mandated environmental compliance costs with a cap, and which should smooth the rate impact of such compliance costs; a narrowly-tailored LFCR that supports EE and DG at any level or pace set by the Commission; and a fixed cost LFCR rate option for residential customers who prefer a known charge rather than the variable LFCR.

The benefits to the Company include sufficient additional revenue that will allow it to provide reliable and safe service while ensuring the financial health of the Company; an LFCR mechanism that will improve TEP's revenue stability and the ECA which should have a positive impact on TEP's financial profile and access to capital. Mr. Hutchens testified that TEP was able to accept a lower non-fuel base rate increase than it originally requested, because of the positive effects of the other adjuster mechanisms provided under the Settlement Agreement.

[245] Settlement Agreement at Attachment B.

In addition to the non-fuel base rate increase, the Settlement Agreement provides for a revised PPFAC, an EE Implementation Plan and revised DSMS, a new LFCR mechanism and a new ECA. For the average residential customer,[246] the rates provided under the Settlement Agreement are projected to have the following bill impacts:[247]

	Current Rates	July 1, 2013	2014[248]
Customer Charge	$7.00	$10.00	$10.00
Delivery Charge	$41.87	$45.90	$45.90
Base Fuel Charge	$22.83	$25.67	$25.67
PPFAC	$5.90[249]	($1.06)[250]	unknown[251]
REST (at cap)	$3.80	$3.80	$3.80
DSMS[252] (June 1)	$0.96[253]	$0.34[254]	$0.32
LFCR (July 1)	NA	$0.00	$0.81[255]
ECA (May 1)	NA	$0.00	$0.19
Total Bill	$82.36	$84.65	Unknown

The immediate impact on a residential customer utilizing 767 kWh per month (the annual average) would be an increase of $2.29, or 2.8 percent, from $82.36 to $84.65. Under the Existing EE Rules Option, the DSMS of $0.002232 per kWh would result in a monthly charge of $1.71 for the average residential consumer. Under this option, the total bill would be $86.02, an increase of $3.66 or 4.4 percent. The impact of the rate increase is substantially mitigated by the reset of the PPFAC, and somewhat by a smaller DSMS.

In future years, the impact of the various adjustors is less clear. In 2014, the DSMS is projected to be minimally smaller, but the LFCR will come into effect. In addition, the PPFAC will be reset, and there could be a charge pursuant to the ECA. TEP estimates that based on a "high case scenario," (i.e. the LFCR and ECA hit their respective caps), in 2014, the LFCR could increase the

[246] The average residential customer uses 767 kWhs per month on an annual basis. The average is higher in the summer and lower in the winter Tr. at 304 (Dukes).
[247] See Ex TEP-8 and Ex TEP-10 (Late Filed).
[248] Effective in the month indicated in the respective POAs.
[249] 767 kWh x $.007696/kWh.
[250] 767 kWh x ($0.001388)/kWh.
[251] The PPFAC rate going into effect under this Order contains a one-time $3 million sulfur credit. This credit will not apply in 2014. Tr. at 89-90. The $3 million credit translates to a little less than $.30 per month per customer on average.
[252] Assumes EERP amortization methodology commencing July 1, 2013.
[253] 767 kWh x $0.001249/kWh.
[254] 767 kWh x $0.000443/kWh.
[255] For purposes of this chart, the charges for the LFCR and ECA are shown as the "highest case" under the cap. Currently, TEP projects the impact of the LFCR in 2014 at $0.21 and the ECA at $0.05. Ex TEP-10.

average residential customer's bill by $.81, and the ECA could add an additional $.19 to the average residential bill. At the same time, the DSMS is projected to decrease $0.02 to $0.32.

The caps on the LFCR and on the ECA limit the effects of these charges to modest levels while providing the Company with rate stability. The Commission retains control over the DSMS through its control over the EE/DSM budgets and its approval of the DSMS. The greatest impact on rates between rate cases will likely be the PPFAC. The PPFAC is affected by many factors, but it is not a new adjustor mechanism, and the Commission and ratepayers have had several years of experience managing rates under this type of adjustor.

TEP has requested approval of several charges related to situations where customers elect to "opt-out" of having their meters read by "smart meters." These charges are set forth in TEP's Statement of Charges, Attachment K to the Settlement Agreement and are reflected in certain proposed tariffs in Attachment J and as may be referred to in TEP's proposed Rules and Regulations. The Commission has an on-going investigative docket on safety, privacy and health issues concerning the use of smart meters, Docket E-00000C-11-0328. Recently, in a letter dated May 23, 2013, the Commission provided notice to stakeholders and interested parties that it is seeking additional information on health issues, and further proceedings may be held by the Commission concerning the matters related to health and smart meters. We believe it is premature to approve TEP's proposed opt-out charges while its investigation into the use of smart meters is pending. Therefore, we shall not determine whether TEP's opt-out charges and tariffs should be approved at this time. Instead, we shall hold the rate case open for this issue until the Commission's investigation is concluded and consider the appropriateness of TEP's opt-out charges and tariffs after the Commission's decision is entered in Docket No. E-00000C-11-0328.

Based on the totality of circumstances, including almost five years under current rates and TEP's significant investment in plant since the last rate case, we find that except for the "smart meter" "opt-out" charges as discussed above, and except for the DSMS as calculated under the EERP as discussed below, the proposed rates under the Settlement Agreement are fair, balanced and reasonable.

. . .

PPFAC Reset

The Settlement Agreement provides that the re-setting of the PPFAC that would normally have occurred on April 1, 2013, be deferred until the implementation of the new rates in this proceeding.[256] The parties want to avoid customer confusion and a yo-yoing effect of rates. Mr. Hutchens testified that by deferring the reset of the PPFAC from April 1 to July 1, TEP will be able to recover an under-collected balance in its PPFAC account.[257] Ratepayers would be paying for these under-collected amounts eventually, and we agree that allowing the current PPFAC rate to continue several additional months before being reset achieves an "elegant" solution to recovering the under-collected PPFAC balances in exchange for a larger decrease that mitigates the immediate impact of the other rates being increased.[258] Consequently, we find that the provision to defer the reset of the PPFAC is in the public interest.

Residential Monthly Customer Charge

The only feature of the Settlement Agreement's proposed base rate design that received opposition was the proposed increase to the monthly service charge for residential customers from $7.00 to $10.00. SWEEP and Sierra Club argued that a $3.00, or 40 percent, increase in this rate component violates the rate design principal of gradualism. We do not agree. As illustrated in the chart above, the proposed monthly service charge of $10 is a small part of the overall average bill of over $84. All other charges are volumetric and we believe that ratepayers retain significant ability to control their bills by altering usage patterns. If the monthly service charge were to be reduced, in order to achieve the same revenue requirement, other rates would need to be increased. The effect of such a rate design change would be to place a greater burden on higher energy users.[259] Higher energy users are often higher income households, but such is not always the case, as retirees or others who are home during the may have higher usage patterns and may not be able to reduce their energy usage. The customer charge recovers the costs directly related to the customers, such as meter

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[256] Settlement Agreement § VI. In Docket Nos. E-01933A-05-0650 and E-01933A-07-0402 (the 2008 Rate Case docket), TEP filed a Motion to Defer the Effective Date of the PPFAC Rate Adjustment.

[257] Tr. at 82-83 (Hutchens). Mr. Hutchens testified that when the PPFAC was re-set in April 2012, the Commission set the rate at a level lower than TEP sought because of the rate impact. He testified that TEP did not have a problem with the lower rate approved at the time, but that the lower forecasted prices behind that decision did not pan out.

[258] Tr. at 247-48 (Higgins).

[259] Tr. at 318 (Dukes).

reading and meter service, as well as a portion of the fixed costs of service.[260] The fixed costs associated with the average residential customer are about $56 per month.[261] To have approximately 18 percent of the fixed costs recovered through a fixed charge is not unreasonable. The benefit to TEP resulting from greater revenue stability outweighs the minimal, if any, negative impact on residential ratepayers from the increase in the monthly service charge. Thus, we find that the modest dollar increase in the basic residential service charge is fair and balanced and should be approved.

<u>Energy Efficiency and DSMS</u>

Currently, TEP does not have an approved EE Implementation Plan for 2011-2012 or beyond. As part of this rate case, TEP proposed a new way to recover the costs of Commission-approved EE/DSM programs and measures. In addition to the recovery methodology, the Settlement Agreement sets out the EE/DSM programs and measures and budgets for which TEP seeks approval for the 2013 EE Implementation Plan Year.

In the 2008 Rate Case, the Commission approved a DSM adjustor mechanism to collect the costs of Commission-approved DSM programs. In order to encourage TEP to engage in DSM programs, the DSMS included a performance incentive. [262] Subsequently, in Decision No. 71819 (August 10, 2010), the Commission adopted the EEE Rules, A.A.C. R14-2-2401 *et seq*. The EEE Rules became effective January 1, 2011, and established goals for electric utilities, including TEP, to reduce retail electric sales each year by a set percentage. For 2011, the savings goal was 1.25 percent; in 2012, the cumulative savings goal was 3.0 percent, and for 2013, the cumulative savings goal is 5 percent. The cumulative savings goal is 22 percent by 2020.

Prior to adopting the EEE Rules, on December 29, 2010, the Commission issued a Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures ("Decoupling Policy Statement").[263] In the Decoupling Policy Statement, the Commission found that "[s]ome form of decoupling or alternative for addressing financial disincentives must be adopted in

[260] Tr. at 305 (Dukes).
[261] Tr. at 305(Dukes).
[262] Decision No. 70628 at 29. The performance incentive established in the 2008 Rate Case allows TEP to recover up to 10 percent of the net benefits from the EE/DSM programs, with a cap of 10 of costs (excluding Low-Income Weatherization, Education and Outreach and Resource Programs.
[263] Docket Nos. E-00000J-08-0314 and G-00000C-08-0314.

order to encourage and enable aggressive use of demand side management programs and the achievement of Arizona's Electric and Gas Energy Efficiency Standards, which will benefit ratepayers and minimize utility costs."[264]

On January 31, 2011, pursuant to A.A.C. R14-2-2405, TEP filed its application for approval of its Energy Efficiency Implementation Plan for 2011-2012 ("2011-12 Implementation Plan"). In the 2011-12 Implementation Plan, TEP proposed DSM programs and measures with budgets totaling $18,182,475 in 2011, and $24,759,193 for 2012; a modification of the Performance Incentive structure (resulting in payments of $16.4 million for two years); a form of a lost fixed cost recovery mechanism entitled an "Authorized Revenue Requirement True-up" ("ARRT") mechanism which was intended to recover revenue requirement associated with EE kWh savings; and a new DSM Surcharge. TEP's 2011-12 Implementation Plan received opposition from several parties, including Staff and AECC, for various reasons. Some of the issues with the Plan involved the program budgets, but the more problematic opposition concerned the TEP's proposed modification of the DSMS mechanism (including new performance incentive metrics) outside of a rate case or without re-opening the 2008 Rate Case. Although the parties to the 2011-12 Implementation Plan attempted to resolve their issues consensually, they were not able to resolve every issue. At an Open Meeting in March 2012, the Commission did not adopt a compromise 2011-12 Implementation Plan that was being recommended by TEP and several other parties, or Staff's alternative plan, and sent the matter for an evidentiary hearing.

In 2012, anticipating the need to fund increased EE/DSM Program investment to achieve EEE Rule goals, TEP had been funding Commission-approved DSM Programs at budget levels greater than the DSMS was designed to collect. When the Commission did not approve an EE Implementation Plan for 2011-2012, TEP cut funding for its DSM Programs back to the levels last approved by the Commission. A hearing was held on the modified 2011-12 Implementation Plan and Staff's alternate plans in July 2012, and a Recommended Opinion and Order ("ROO") was issued on August 21, 2012.[265]

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[264] Decoupling Policy Statement at 30.
[265] *See* Docket No. E-01933A-11-0055.

In the meantime, on July 2, 2012, TEP filed its Rate Application in this docket. The Rate Application included an EERP that proposed a new way to recover the costs of Commission-approved EE/DSM Programs. As originally conceived by TEP, the Commission would approve a three-year EE Program budget; the costs of the Programs would be treated as a regulatory asset and amortized over four years; and TEP would collect the amortization costs, including a return on investment, through its DSMS surcharge. Some of the parties in this case had concerns about certain of the specifics of TEP's original proposal. In its Direct Testimony, Staff recommended modifications to TEP's proposal, but kept the concept of a regulatory asset. The Settlement Agreement adopts a version of the EERP based on Staff's recommendations. Under this version, the Commission continues to approve annual Implementation Plans, the investments incur carrying costs at the WACC, and the amortization period is five years. No party in this proceeding, including SWEEP or Sierra Club, objected to the EERP contained in the Settlement Agreement.

The EERP in the Settlement Agreement adopts Staff's recommended programs and budgets for EE/DSM Programs for the remainder of 2013 as follows:

TEP DD/DSM Programs	**July 2013-Dec 2013**
Residential Efficiency Programs	
Low-Income Weatherization	$308,226
Appliance Recycling	$429,767
Residential New Construction	$883,423
Existing Home (was Efficient Home Cooling)	$1,757,443
Shade Tree Program	$162,791
Efficient Products ("CFL")	$1,215,748
Residential & Small Commercial DLC	$92,408
Multi-Family Direct Install	$84,869
Residential Subtotal	**$4,934,674**
Non-Residential Efficiency Programs	
Bid for Efficiency	$251,546
C&I Comprehensive Program	$2,142,928
Small Business Direct Install	$1,460,543
Commercial New Construction	$203,160
CHP Joint Program (Pilot)	$11,000
C&I Schools Program	$78,971
C&I DLC	$1,375,890
Retro-Commissioning	$87,760
Non-Residential Subtotal	**$5,611,886**
Support Programs	
Education and Outreach	$97,000
Residential Energy Financing	$221,323

Codes Support	$37,745
Support Programs Subtotal	**$356,068**
Behavioral Programs	
Home Energy Reports	$336,895
Behavioral Comprehensive Program	$805,502
Behavioral Subtotal	**$1,142,397**
Program Totals	**$12,045,024**
Program Develop, Analysis & Reporting Software	$324,573
Subtotal	**$324,573**
Total	**$12,369,596**

The above budget is for the second half of 2013. In March 2013, TEP began to fund EE/DSM Programs that had previously received Commission approval. Because of the time necessary to ramp up the programs, even with starting funding in March, TEP believes that the $12.3 million budget for 2013 is reasonable.[266]

The tenor of the public comments received in Docket No. E-01933A-11-0055 and in the course of this proceeding, indicate that there is great interest and support within the TEP service area for EE/DSM programing. No party to this proceeding opposes the EERP. The Programs set forth above received much scrutiny in Docket No. E-01933A-11-0055, and Staff found them to be cost-effective. There is no opposition to their adoption at the recommended funding levels. Regardless of the mechanism for recovering approved EE/DSM Program costs, we find that only the proposed EE/DSM Programs and budgets adopted in the Settlement Agreement, and which have already been approved by the Commission in previous decisions, should be approved.

The Settlement Agreement proposes an EERP that would treat TEP's costs associated with Commission-approved EE/DSM Programs as a regulatory asset. By approving the EE/DSM programs, the Commission would authorize TEP to charge the allowable costs as they are incurred to the appropriate regulatory asset account.[267]To qualify to be recovered in the DSMS, the allowable program costs must result in a minimum annual portfolio savings (kWh) and not exceed the maximum portfolio level costs ($ per kWh) as set by the Commission. Under the EERP POA, for 2013, and until reset by the Commission, the minimum annual portfolio level savings is set at 84,024,000 kWh, and the maximum portfolio cost is $0.02208 per kWh.[268] As it considers each

[266] Tr. at 152-53. (Hutchens).
[267] Settlement Agreement, Attachment D (EERP POA).
[268] Settlement Agreement Attachment D at § 6.C.

yearly Implementation Plan, the Commission may determine the appropriate performance metrics to apply to that year's programs. Qualifying program costs will then be amortized over five years, with TEP earning a carrying charge equivalent to its WACC. There will no longer be a Performance Incentive paid to TEP as under the current DSMS approved in the 2008 Rate Case.

Under the EERP, in 2013, customers will pay a DSMS of $0.000443 per kWh which is designed to recover the costs of the previously approved EE/DSM programs and performance incentives that have not yet been recovered. In 2014, TEP estimates that residential customers are projected to pay a DSMS of $0.000411 per kWh, with a bill impact of $0.32 for the average residential customer, to recover 1/5 of the approved 2013 EE/DSM costs. In 2015, the DSMS would include 1/5 of the 2013 EE/DSM Programs, plus 1/5 of the qualifying EE/DSM costs for the 2014 plan year. TEP estimates that the average residential customer would see a DSMS of $0.001078 per kWh, with a bill impact of $0.83 for the average residential customer. In 2016, the DSMS will be set to recover 1/5 of the 2013 qualifying costs, 1/5 of the 2014 qualifying costs, plus 1/5 of the 2015 qualifying costs. TEP estimates the 2015 DSMS to be $0.001764 per kWh, with a bill impact of $1.35 for the average residential customer. A chart of the projected DSMS and bill impact for the average residential customer under the EERP is as follows:

Year	DSM Surcharge	Average Monthly Residential Bill
2013	$0.000443	$0.34
2014	$0.000411	$0.32
2015	$0.001078	$0.83
2016	$0.001764	$1.35
2017	$0.002421	$1.86
2018	$0.003049	$2.34
2019	$0.003358	$2.58
2020	$0.003468	$2.66
2021[269]	$0.003548	$2.72
2022	$0.002977	$2.28
2023	$0.002063	$1.58
2024	$0.001347	$1.03
2025	$0.000660	$0.51

[269] The chart only reflects the surcharge for programs approved up to 2020. The 2020 program costs would be collected in 2021 through 2015 under the EERP. Under the Existing EE Rule Option, the year's program costs are collected over the course of the year as the programs are implemented.

An alternative to amortizing the EE/DSM costs, is the Existing EE Rules Option, under which approved costs are collected over the course of a year. For the period 2013 through 2020 the DSMS under the Existing EE Rules Option is estimated as follows:[270]

Year	DSM Surcharge	Average Monthly Residential Bill
2013	$0.002232	$1.71
2014	$0.003015	$2.31
2015	$0.003282	$2.52
2016	$0.003357	$2.57
2017	$0.003416	$2.62
2018	$0.003515	$2.70
2019	$0.003613	$2.77
2020	$0.003709	$2.84

The projected DSM charge and bill impact are greater for each year under the annual methodology, but under the amortization methodology of the EERP, consumers pay for a longer period of time.

Settlement proponents believe that the EERP methodology for recovering the costs of EE/DSM programs offers greater benefit because it will smooth the effect of the program costs for ratepayers; the costs and benefits of the programs are better synchronized; and the EE/DSM funding is more stable.

We do not believe the record is sufficient to allow us to make a determination that either the EERP or the Existing EE Rules Option is the best methodology for recovering the costs of approved EE/DSM programs. Adoption of the EERP as advocated by the settlement proponents would represent a fundamental shift in the way that we have addressed cost recovery of EE/DSM. While TEP's present EE/DSM recovery mechanism classifies EE/DSM costs as expenses, the proposed EERP would treat them as invested capital.

In balancing the public interest on the record, we are unable to conclude that EERP is a reasonable way to recover the costs of approved EE/DSM programs. In addition, the current method "the Existing EE Rules Option" for recovery of EE/DSM program costs is not ideal. We recognize

[270] Ex TEP-9.

and appreciate that the parties were working in a paradigm under the current EE Rules. However, as Commissioner Gary Pierce stated in a May 9, 2013 letter to Docket No. RE-00000C-09-0427, "it would make sense to look at more closely aligning energy efficiency with the IRP process." We find that assessment to be reasonable.

Although we are aware that EE/DSM programs can provide benefits to customers; nonetheless, the record before us shows that these programs come with substantial costs. When designing an EE/DSM recovery mechanism, we must balance our efforts to mitigate the substantial ratepayer burdens associated with funding these costs against the Company's interests in achieving timely and efficient cost recovery. We want to be clear that we support cost effective energy efficiency. However, we believe that the time has come for us to engage in a full consideration of the issues related to EE/DSM programs and their cost recovery, including whether EE/DSM should be considered as a resource in integrated resource plans.

Consequently, we will open a new generic docket to address energy efficiency and cost recovery methodologies on these matters, which may include the EERP, the Existing EE Rules Option, EE/DSM as part of an integrated resource plan and alternative options proposed by any party. The Commission advises the parties that these additional proceedings should, at a minimum, address the following issues:

1) Do EE/DSM mechanisms provide a means of cost recovery that is economically efficient, fair, and reasonable to utilities and their ratepayers?
2) Should existing EE/DSM mechanisms be modified to either eliminate or reduce recovery of performance incentives?
3) Should EE/DSM programs and their costs be considered as resources an integrated resource plan?
4) Do any factors warrant modification or suspension of the compliance obligations under the EE Rules?

In addition, the parties are reminded that the Commissioners may provide letters to the docket to identify other issues that should be addressed in this proceeding.

In the interim, in order to collect the Program costs that we approve herein (approximately $10.5 million for 2013) we adopt a DSMS as calculated under the Existing EE Rules Option as described in Mr. Hutchen's revised Exhibit TEP-11. That DSMS includes a performance incentive to be calculated by taking 8 percent of the net benefits (as reported in TEP's March 1 DSM progress report) but capped at $0.0125/kWh saved, which is similar to the performance incentive recently approved for APS in Docket No. E-01345A-12-0224. The DSM is set at $0.002232 per kWh for residential customers and 2.5479 percent of the total bill (before RES, LFCR, assessments and taxes) for non-residential customers. The DSMS we set at this time shall remain in effect until further order of the Commission.

In the event the Commission is unable to approve new programs and DSMS mechanism to go into effect January 1, 2014, the DSMS and program funding we approve herein shall continue at the levels approved herein (i.e. at an annual level of approximately $21.0 million).

LFCR

Because most of TEP's revenue requirement is recovered through volumetric charges,[271] the Commission recognizes that by complying with the EEE Rules' mandate to reduce energy sales, without a way to recover the fixed costs that would otherwise have been recovered through kWh sales, TEP would not be given a reasonable opportunity to recover its authorized revenue requirement. In recent years, the Commission has approved some sort of lost fixed cost recovery mechanism. For Southwest Gas, the mechanism was a modified revenue decoupling mechanism; for UNS Gas and APS, the Commission approved an LFCR mechanism that was more narrowly drafted than for Southwest Gas. The proposed LFCR mechanism for TEP is similar to the one that we approved for APS and is designed to recover only those lost fixed costs associated with Commission-approved EE/DSM programs. Because some consumers might not like the uncertainly of a per-kWh charge, the Settlement Agreement contains a provision that they may opt for a fixed monthly charge.

SWEEP and Sierra Club oppose the LFCR mechanism because they believe only full revenue

[271] Tr. at 81. For the typical residential user, $70 of the total bill of $80 would be collected through volumetric rates.

decoupling will remove the financial disincentives inherent in EE/DSM efforts and to have utility companies fully embrace EE as a true generation resource. They recommend that the Commission substitute full revenue decoupling for the LFCR.

The record is not fully developed in this docket to allow us to adopt full revenue decoupling. No party has offered a full revenue decoupling mechanism in this proceeding. SWEEP and Sierra Club may be right that additional benefits might accrue in the arena of EE as a result of full revenue decoupling, but at this point in time, we continue to believe that additional public education is needed before such an overhaul of the cost recovery would be embraced. It would not be reasonable to adopt the EE/DSM programs and require TEP to meet kWh sales savings without also approving a mechanism that would allow TEP to recover the fixed costs associated with the lost kWh sales. Because of the earlier uncertainty surrounding TEP's EE/DSM Programs, it is important that we approve an EE Implementation Plan at this time. There is no full revenue decoupling proposal before us, and it is not in the public interest to delay approval of the EE Implementation Plan while we engage in further debate on full revenue decoupling.

We find that an LFCR, proposed in this case, is sufficient to allow TEP to recover the lost fixed costs associated with Commission approved EE/DSM programs and the opportunity to earn its authorized revenue requirement but we would like to see it reflected in a different manner. Recent developments, arising out of another rate case, revealed to us that many ratepayers are confused and frustrated by the implementation of an LFCR. We believe that the LFCR should be split into two halves; an Energy Efficiency LFCR and a Distributed Generation LFCR. Each of these separate LFCR provisions should be indicated on the ratepayer's monthly bill.

However, SWEEP and the Sierra Club have made intriguing arguments that full revenue decoupling might be in the public interest because it might lower TEP's financial disincentives. But, Staff, AECC and other parties were reluctant to support full revenue decoupling because of possible adverse effects on demand charges, among other reasons. Therefore, TEP shall file an annual report detailing what full revenue decoupling would look like if it had been approved. TEP will file the Full Revenue Decoupling Report, along with the calculated LFCR Annual Adjustment, including all Compliance Reports, with the Commission for the previous year by May 15th of each year. TEP's annual report will reflect what rates and average utility bills would have been for residential, small commercial and large industrial customers, if full revenue decoupling had been approved in this Decision.

Based on the totality of circumstances, we find that the Settlement Agreement as modified herein, provides benefits to ratepayers, shareholders and the community, and represents a fair and balanced resolution of all of the issues presented except with respect to approving the "smart meter" "opt-out" charges discussed herein and except with respect to the DSMS, the EERP and Existing EE Rules Option as discussed herein. We find that the Settlement Agreement as modified herein is in the public interest and approve it.

* * * * * * * * * *

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

FINDINGS OF FACT

1. TEP is a public service corporation principally engaged in furnishing electric energy to an area in and around Tucson, Arizona, and to Fort Huachuca in Cochise County, Arizona.

2. TEP's current rates and charges were established in Decision No. 70628.

3. On July 2, 2012, TEP filed with the Commission its Rate Application seeking an increase in base rates of $127.8 million, or 15.3 percent, to become effective July 1, 2013. The requested increase was based on a test year ending December 31, 2011.

4. On August 2, 2012, Staff notified the Company that its application was sufficient

under A.A.C. R14-2-103 and classified TEP as a Class A utility.

5. On August 3, 2012, TEP and Staff filed a Request for Procedural Schedule and submitted a proposed procedural schedule.

6. On August 6, 2012, RUCO filed a Response to the Joint Request for Procedural Schedule, suggesting modification of the proposed schedule.

7. On August 6, 2012, Staff and TEP filed a Proposed Form of Public Notice.

8. On August 13, 2012, TEP, Staff, and RUCO filed a Revised Proposed Procedural Schedule.

9. On August 17, 2012, TEP docketed a Notice of Errata, providing corrected bill impact calculations.

10. A Procedural Conference for the purpose of discussing the schedule convened on August 28, 2012, at the Commission's Tucson office.

11. By Procedural Order dated September 6, 2012, the matter was set for hearing on March 6, 2013, and other procedural guidelines and timelines were established. A Public Comment meeting was scheduled for March 4, 2013, at the Commission's Tucson offices.

12. On October 1, 2012, TEP had notice of the hearing published it the *Arizona Daily Star*; and posted in the Joel Valdez Main Library in Tucson, Arizona on September 14, 2012; and posted on the TEP website.

13. TEP mailed the public notice as a bill insert beginning on October 2, 2012, and ending on October 31, 2012.

14. Intervention in this docket was granted to RUCO, SAHBA, AECC, EnerNOC, Kroger, APS, SWEEP, IBEW Local 1116, Sierra Club, DOD, AIC, Cynthia Zwick, SAWUA, Vote Solar, SEIA, AriSEIA and Opower.

15. On December 21, 2012, Staff, AECC, AIC, EnerNOC, IBEW Local 1116, Kroger,

Opower, RUCO, SAHBA, Sierra Club and SWEEP filed direct non-rate design testimony.

16. On January 8, 2012, TEP filed a notice of settlement discussions.

17. On January 11, 2013, Staff, AECC, DOD, Kroger, RUCO, SAWUA, SEIA, SWEEP, Vote Solar and Ms. Zwick filed direct testimony regarding rate design and cost of service.

18. Settlement discussions began on January 15, 2013, and resulted in a Preliminary Term Sheet, describing a proposed settlement in principle, that Staff filed in this docket on January 22, 2013.

19. The Commission discussed the Preliminary Term Sheet in a Special Open Meeting on January 23, 2013.

20. On February 1, 2013, Commissioner Gary Pierce filed a letter to the docket concerning the EE provisions described in the Preliminary Term Sheet.

21. On February 4, 2013, a proposed Settlement Agreement signed by TEP, Staff, RUCO, SAHBA, Kroger, Freeport-McMoRan, AECC, EnerNOC, IBEW Local 1116, Cynthia Zwick, AIC, Opower, and Vote Solar was docketed.

22. SWEEP, Sierra Club and APS participated in settlement discussions but did not sign the Settlement Agreement. APS takes no position on the Settlement Agreement.

23. On February 14, 2013, TEP filed an affidavit of posting the Public Comment Meeting as a bill message on customers' bills beginning January 2, 2013, and ending on February 1, 2013.

24. On February 15, 2013, TEP, AECC, RUCO, IBEW Local 1116, Cynthia Zwick, AIC, SAHBA, SAWUA, EnerNOC, Opower, Vote Solar and Staff filed testimony in support of the Settlement Agreement, and SWEEP filed testimony in partial opposition to the Settlement Agreement.

25. On March 1, 2013, TEP, AECC and SWEEP filed responsive testimony regarding the Settlement Agreement.

26. On March 1, 2013, TEP filed an updated version of the Settlement Agreement which included an updated cover page that includes all signatories (including those who signed on and after February 4, 2013); an updated Attachment "D" which is the POA for the EERP; an updated Attachment "F" the LFCR POA; an updated Attachment "J" regarding rate design; and an updated Attachment "K" which is the Statement of Charges. A copy of the updated Settlement Agreement is attached hereto as Exhibit A.

27. The Commission received a number of written comments in this matter and held a Public Comment Meeting on March 4, 2013, starting at 5:30 p.m. at its Tucson offices. In general, comments objected to the magnitude of the proposed increase, expressed support for, or opposition to, full revenue decoupling, and supported resumption of funding for energy efficiency programs.

28. The evidentiary hearing on the Settlement Agreement commenced on March 6, 2013, and continued on March 7 and 8, 2013. David Hutchens, the Company's president, and Dallas Dukes, the Company's Senior Director of Pricing and Economic Forecasting Groups, testified on behalf of TEP; Steve Olea, Director of the Commission's Utilities Division, and Howard Solganick, a consultant with Energy Tactics & Services, Inc., testified for Staff; Patrick Quinn, the Director of RUCO, testified on behalf of RUCO; Gary Yaquinto, the President of AIC, testified on behalf of AIC; Kevin Higgins, a principal in the consulting firm Energy Strategies, testified on behalf of AECC; David Goldewski, President of SAHBA testified on its behalf; Richard Darnall, executive consultant with Utilities Consulting Group, LLC, testified on behalf of SAWUA; Mona Tierny-Lloyd, Director of Regulatory Affairs for EnerNOC, testified for EnerNOC; Cynthia Zwick testified on her own behalf; Rick Gilliam, Director of Research testified for Vote Solar; and Jeff Schlegel, Arizona's representative to SWEEP, testified for that organization. The pre-filed testimony in support of the Settlement Agreement of Frank Grijalva, Business Manager/Financial Secretary for IBEW Local 1116, was admitted into evidence by stipulation of the parties, as was the Settlement

Agreement testimony of Diana Genasci, Manager of Opower Market Development and Regulatory Affairs. In addition to the testimony filed in support of and in opposition to the Settlement Agreement, the pre-settlement pre-filed testimony of all parties was admitted.

29. On March 18, 2013, TEP filed Late-Filed exhibits as discussed during the hearing, including the numerical values used to create the graph set forth on page 20 of David Hutchen's Direct Testimony in Support of the Settlement Agreement; the estimated monthly bill impacts for the LFCR mechanism, the ECA and the DSM Surcharge; and a revised version of Exhibit DGH-2 to David Hutchen's Direct Testimony in Support of the Settlement Agreement addressing the specific percentage rate for the DSM Surcharge to be applied to the non-residential customer bills.

30. On March 21, 2013, SAHBA, EnerNOC, and SAWUA filed Initial Briefs.

31. On March 22, 2013, TEP, AECC, SWEEP, IBEW Local 1116, Vote Solar, Sierra Club, AIC and Staff filed Initial Briefs; AECC filed a Joinder in TEP's Initial Brief and provided an additional clarifying statement; and RUCO filed a Supplemental Brief to TEP's Closing Brief.

32. On March 29, 2013, TEP filed a notice that it would not be filing a Post-Hearing Reply Brief; Opower filed a Responsive Brief and Partial Joinder in TEP's Closing Brief; and SWEEP filed a Reply Brief.

33. The settlement discussions in this docket were open, transparent, and inclusive of all parties who desired to participate. All parties were notified of the settlement proceedings and had the opportunity to be heard and have their issues fairly considered.

34. Except for the EERP, the Settlement Agreement and its provisions are in the public interest and should be approved as discussed herein.

35. TEP's adjusted OCRB is $1,507,062,648 and the fair value of TEP's jurisdictional rate base for the test year ending December 31, 2011, is $2,268,199,253.

36. TEP's total adjusted test year revenue is $813,401,411.

37. TEP's actual test year end capital structure consisting of 55.97 percent long-term debt, 0.53 percent short-term debt, and 43.5 percent common equity is appropriate for establishing rates in this matter.

38. A return on common equity of 10.0 percent, an embedded cost of long-term debt of 5.18 percent, and a cost of short-term debt of 1.42 percent are appropriate estimates of the cost of capital for purposes of this Settlement Agreement. TEP's Weighted Average Cost of Capital is 7.26 percent.

39. A FVROR of 5.05 percent on TEP's FVRB produces rates that are just and reasonable.

40. TEP should be authorized a non-fuel base rate increase of $76,194,257.

41. A Base Cost of Fuel and Power of $0.032335 per kWh is appropriate, and results in a fuel-related revenue increase of $31,599,892.

42. TEP's PPFAC rate shall be reset at negative $.001388 per kWh to be effective contemporaneously with the new rate adopted herein. The negative PPFAC rate reduces the annual recovery of fuel costs by $52,750,597.

43. The record is not sufficient to permit us to make a determination that either the EERP or the Existing EE Rules Option is the best methodology for recovering the costs of approved EE/DSM programs, and it is in the public interest to open a new generic docket to address energy efficiency and various methodologies for the recovery of approved EE/DSM program costs. Until the Commission can deliberate and adopt a recovery methodology, it is in the public interest to recover the costs of the EE/DSM programs approved herein pursuant to the Existing EE Rules Option discussed in TEP Exhibit 11.

44. The DSMS rate until further Order of the Commission is $0.002232 per kWh for residential customers and 2.5479 percent of the total bill (before RES, LFCR, assessments and taxes)

for non-residential customers.

45. It is in the public interest not to adopt TEP's proposed "smart meter" "opt-out" charges while the Commission's investigation concerning the use of smart meters is on-going in Docket E-00000C-11-0328, and to hold this docket open until the Commission's investigation is concluded and the Commission's Decision in that docket is entered, and we are able to consider the appropriateness of TEP's opt-out charges, tariffs and related references to TEP's proposed Rules and Regulations consistent with the findings in that docket.

46. The record in this matter should remain open until July 1, 2014, as described in Section XV of the Settlement Agreement to allow for the possible adjustment of specific tariffs to correct unintended rate impacts that are determined to be inconsistent with the public interest.

CONCLUSIONS OF LAW

1. TEP is a public service corporation within the meaning of Article XV of the Arizona Constitution, and A.R.S. §§ 40-203, -204, -221, -250 and -361.

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

3. Notice of the Rate Application and hearing was provided in accordance with the law.

4. Adoption of the Settlement Agreement as modified and discussed herein is in the public interest.

5. The rates and charges produced by the Settlement Agreement are just and reasonable except that we do not adopt the proposed "smart meter" "opt-out" charges at this time and except that until further Order of the Commission the DSMS shall be $0.002232 per kWh for residential customers and 2.5479 percent of the total bill (before RES, LFCR, assessments and taxes) for non-residential customers.

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ORDER

IT IS THEREFORE ORDERED that the Settlement Agreement dated February 4, 2013, and updated March 1, 2013, and attached to this Decision as Exhibit A, is hereby approved as modified and discussed herein.

IT IS FURTHER ORDERED that Tucson Electric Power Company is hereby directed to file with the Commission on or before July 1, 2013, revised schedules of rates and charges and Plans of Administration consistent with Exhibit A as modified and the findings herein.

IT IS FURTHER ORDERED that the revised schedules of rates and charges shall be effective for all service rendered on and after July 1, 2013.

IT IS FURTHER ORDERED that the docket shall be held open until July 1, 2014, in order to allow for the Commission to conclude its investigation of smart meters and to consider the appropriateness of Tucson Electric Power Company's proposed "smart meter" "opt-out" charges, tariffs and related references to Tucson Electric Power Company's proposed Rules and Regulations the possible adjustment of specific tariffs to correct for unintended rate impacts that are determined to be inconsistent with the public interest, however any such adjustments shall not have the effect in the aggregate of changing Tucson Electric Power Company's non-fuel revenue requirement.

IT IS FURTHER ORDERED that energy efficiency and the methodology for recovery of approved EE/DSM costs shall be reviewed, established and approved as appropriate as part of the Commission's Energy Efficiency Implementation Plan and DMS Surcharge reset proceedings for Tucson Electric Power Company.

IT IS FURTHER ORDERED that the performance incentives, tied to the cost effective energy savings, shall be reviewed, established and approved as appropriate as part of the Commission's Energy Efficiency Implementation Plan and DSM Surcharge reset proceedings for Tucson Electric Power Company.

IT IS FURTHER ORDERED that Tucson Electric Power Company shall notify its affected customers of the revised schedules of rates and charges authorized herein by means of an insert in its next regularly scheduled bill and by posting on its website, in a form acceptable to the Commission's Utilities Division Staff.

IT IS FURTHER ORDERED that Tucson Electric Power Company shall implement and comply with the terms of the Settlement Agreement as modified herein.

IT IS FURTHER ORDERED that the revised Rules and Regulations set forth in Exhibit TEP-5 are approved.

IT IS FURTHER ORDERED that Tucson Electric Power Company shall meet with the Arizona Corporation Commission's Utilities Division Staff and the Residential Utility Consumer Office in the 4th quarter of each year to satisfy Section 20.4 of the Settlement Agreement.

IT IS FURTHER ORDERED that Tucson Electric Power Company shall file on or before August 30, 2013, a revised Partial Requirements Service Tariff and a Super-Peak Time-of-Use Tariff.

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IT IS FURTHER ORDERED that Tucson Electric Power Company shall file a Full Revenue Decoupling Report, along with the calculated LFCR Annual Adjustment, per the LFCR Plan of Administration. The Full Revenue Decoupling Report shall reflect what rates and average utility bills would have been for residential, small commercial and large industrial customers, if full revenue decoupling had been approved in this Decision.

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, JODI JERICH, 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 27th day of June 2013.

Jodi A. Jerich

JODI JERICH
EXECUTIVE DIRECTOR

DISSENT ____________________

DISSENT ____________________

SERVICE LIST FOR: TUCSON ELECTRIC POWER COMPANY

DOCKET NO.: E-01933A-12-0291

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EXHIBIT A

TUCSON ELECTRIC POWER COMPANY

PROPOSED SETTLEMENT AGREEMENT

DOCKET NO. E-01933A-12-0291

FEBRUARY 4, 2013

(UPDATED MARCH 1, 2013)

DECISION NO. 73912

TABLE OF CONTENTS

PROPOSED SETTLEMENT AGREEMENT OF DOCKET NO. E-01933-A-12-0291 TUCSON ELECTRIC POWER COMPANY REQUEST FOR RATE ADJUSTMENT

The purpose of this Settlement Agreement ("Agreement") is to settle disputed issues related to Docket No. E-01933A-12-0291, Tucson Electric Power Company's ("TEP" or "Company") application to increase rates. This Agreement is entered into by the following entities:

Tucson Electric Power Company
Arizona Corporation Commission Utilities Division ("Staff")
Residential Utility Consumer Office ("RUCO")
Southern Arizona Homebuilder's Association ("SAHBA")
Kroger Co. ("Kroger")
Freeport-McMoRan Copper & Gold Inc. ("Freeport-McMoRan")
Arizonans for Electric Choice and Competition ("AECC")
EnerNOC, Inc. ("EnerNOC")
IBEW Local 1116 ("IBEW")
Cynthia Zwick ("Zwick")
Arizona Investment Council ("AIC")
Opower, Inc. ("Opower")
The Vote Solar Initiative ("Vote Solar")
U.S. Department of Defense and all other Federal Executive Agencies ("DOD")
Southern Arizona Water Users Association
Arizona Solar Energy Industries Association
Solar Energy Industries Association

These entities shall be referred to collectively as "Signatories;" a single entity shall be referred to individually as a "Signatory."

I. RECITALS

1.1 TEP filed the rate application underlying Docket No. E-01933A-12-0291 on July 2, 2012. Staff found the application sufficient on August 2, 2012.

1.2 Subsequently, the Arizona Corporation Commission ("Commission") approved applications to intervene filed by SAHBA, Kroger, Freeport-McMoRan and AECC (collectively "AECC"), RUCO, EnerNOC, Arizona Public Service, Southwest Energy Efficiency Project, IBEW, Sierra Club, DOD, Solar Energy Industries Association, AIC, Cynthia Zwick, Opower, Vote Solar, Arizona Solar Energy Industries Association and Southern Arizona Water Users Association (collectively "Parties").

1.3 TEP filed a notice of settlement discussions on January 8, 2013. Settlement discussions began on January 15, 2013. The settlement discussions were open, transparent, and inclusive of all Parties to this Docket who desired to participate. All Parties to this Docket were notified of the settlement discussion process, were encouraged to participate in the negotiations, and were provided with an equal opportunity to participate. Staff filed a Preliminary Term Sheet regarding this matter on January 22, 2013, which was discussed in a Special Open Meeting held on January 23, 2013.

1.4 The terms of this Agreement are just, reasonable, fair, and in the public interest in that they, among other things, establish just and reasonable rates for TEP customers; promote the convenience, comfort and safety, and the preservation of health, of the employees and patrons of TEP; resolve the issues arising from this Docket; and avoid unnecessary litigation expense and delay.

1.5 The Signatories believe that this Agreement balances the interests of both TEP and its customers. These benefits include:

- a limited first year bill impact for customers (less than $3.00 per month[1] for a residential customer using the annual average of 767 kilowatt-hour ("kWh") per month) despite the fact that TEP's current rates will have been in effect for almost 5 years at the time the new rates go into effect;
- a lower percentage rate impact on small commercial customers than the other customer classes;

[1] This includes the PPFAC and the DSM surcharge but does not include the REST surcharge, taxes or assessments.

- continuing bill assistance for low income customers;
- a proposal that provides rate treatment for investments in energy efficiency in a manner similar to rate treatment for investments in other resources and that reduces the rate impact to the customer;
- an Environmental Compliance Adjustment ("ECA") mechanism that allows recovery, with a cap, of government-mandated environmental compliance costs in a manner that smooths the rate impact of such compliance;
- a narrowly-tailored Lost Fixed Cost Recovery ("LFCR") mechanism that supports energy efficiency ("EE") and distributed generation ("DG") at any level or pace set by this Commission; and
- a fixed cost LFCR rate option for residential customers preferring to a pay a specified charge for lost fixed costs rather than the variable LFCR.

1.6 The Signatories agree to ask the Commission (1) to find that the terms and conditions of this Agreement are just and reasonable and in the public interest, along with any and all other necessary findings, and (2) to approve the Agreement such that it and the rates contained herein may become effective on July 1, 2013.

TERMS AND CONDITIONS

II. RATE INCREASE

2.1 TEP shall receive a non-fuel base rate increase of $76,194,000 over adjusted test-year retail revenues, reflecting a total non-fuel revenue requirement of $659,724,574. Attachment A sets forth the adjustments to TEP's initial request for a non-fuel base rate increase of $127,760,000 that results in the settlement amount.

2.2 TEP's base fuel rates shall be set to recover a total of $300,252,951 which is an annual increase of $31,599,730 over the amount recovered through current base fuel rates. However, as agreed to in this Agreement, the Purchased Power and Fuel Adjustment Clause ("PPFAC") rate will be reset on the effective date of the new rates, which will reduce the present annual recovery of fuel costs by $52,750,597.

2.3 The Company's jurisdictional fair value rate base used to establish the rates agreed to herein is $2,268,199,253, representing an average of the original cost rate base of $1,507,062,648 and the replacement cost new less depreciation rate based of $3,029,335,858. The Company's total adjusted Test Year revenue requirement is $959,977,525.

III. BILL IMPACT

3.1 Upon the effective date of the new rates, the monthly bill for a residential customer, using the annual average of 767 kWh per month, will increase by less than $3.00. This overall impact reflects a base rate increase, as well as a reduction in the PPFAC rate and a reduction in the Demand Side Management ("DSM") surcharge resulting from the adoption of the proposed Energy Efficiency Resource Plan.

3.2 The percentage revenue allocation resulting from this Agreement among the customer classes is set forth in Attachment B.

IV. COST OF CAPITAL

4.1 The actual test year capital structure comprised of 55.97% long term debt, 0.53% short term debt and 43.50% common equity shall be adopted.

4.2 A return on common equity of 10.0%, an embedded cost of long-term debt of 5.18% and a cost of short-term debt of 1.42% shall be adopted.

4.3 A fair value rate of return of 5.05%, which includes a rate of return on the fair value increment of rate base of 0.68%, shall be adopted.

4.4 The provisions set forth herein regarding the quantification of cost of capital, fair value rate base, fair value rate of return, and the revenue requirement are made for purposes of settlement only and should not be construed as admissions against interest or waivers of litigation positions related to other or future cases.

V. DEPRECIATION/AMORTIZATION

5.1 The depreciation and amortization rates proposed by TEP and contained in Exhibit REW-1 to Dr. Ron White's Pre-filed Direct Testimony shall be adopted until further order of the Commission.

VI. PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE ("PPFAC")

6.1 The average retail base fuel rate shall be set at $0.032335 per kWh. This rate reflects a total of $300,252,951 in annual fuel and purchased power costs. This base rate does not include the PPFAC rate established in this Agreement, which includes a one-time $3 million credit related to previous sulfur credits and a $9.7 million deferral of costs related to the San Juan Thermal Event (as described in Section XIV below). Therefore, on the effective date of new rates in this docket, the PPFAC rate will be set at negative $0.001388 per kWh (i.e., it will be a credit to the customer's bill).

6.2 TEP's existing PPFAC mechanism will continue with administrative changes, as set forth in the PPFAC Plan of Administration in Attachment C. The PPFAC is modified to include the recovery of the following costs and/or credits: broker fees; lime costs; sulfur credits; and 100% of proceeds from the sale of SO2 allowances. TEP will continue to recover its base purchased power and fuel costs through base fuel rates as determined by the Commission in this case. TEP will continue to file annually for the reset of the PPFAC and Staff will review the filings for the appropriateness of the forecasts and the numerical accuracy of the filing. Such Staff review does not imply prudency.

6.3 The Signatories believe it is in the public interest to defer the next reset of TEP's PPFAC rate until the effective date of the rates in this docket in order to partially offset the base rate increase. Therefore, TEP will seek expedited Commission authorization to defer TEP's April 1, 2013 PPFAC rate adjustment until the effective date of new rates in this docket and the Signatories agree to either support or not oppose that motion.

VII. ENERGY EFFICIENCY RESOURCE PLAN

7.1 TEP will implement an Energy Efficiency Resource Plan ("Plan"), as proposed by Staff in its Direct Testimony, which is intended to treat energy efficiency similar to a typical generation resource. Under this Plan, TEP will invest (just as TEP does with other conventional energy resources) in cost-effective energy efficiency programs that have been approved by the Commission. After providing documentation that the energy efficiency programs have been effective, TEP will be allowed to recover the cost of its energy efficiency investments, including the rate of return established in this case on those investments, through TEP's existing DSM adjustor mechanism.

7.2 TEP will amortize annual energy efficiency investments under the Plan over five years.

7.3 TEP will resume funding programs previously approved by the Commission beginning March 1, 2013, and shall request recovery of such costs through the Plan.

7.4 Upon the effective date of the rates in this case, TEP will begin investing in cost-effective DSM/EE programs pursuant to the Plan for the remainder of year 2013 based upon the Commission's approval of the Plan, which includes the programs and the annual budget (approximately $12 million on a pro rata basis assuming a July 1, 2013 start date) recommended by Staff in Staff's proposed order for TEP's 2011-2012 Energy Efficiency Implementation Plan filed in Docket No. E-01933A-11-0055 on November 16, 2011.

7.5 Upon the effective date of the rates in this case, and approval of the Plan, TEP will file a request to close Docket No. E-01933A-11-0055.

7.6 Any customer who can demonstrate an active DSM program and whose single site usage is 25 MW or greater may file a petition with the Commission for an exemption from the DSM adjustor and, if approved, will be removed from the Energy Efficiency Standard denominator. The Parties are not required to support any such petition and some Parties may plan to oppose any such petition.

7.7 TEP will conduct the Plan pursuant to a Plan of Administration, which is set forth in Attachment D.

7.8 Upon adoption of the Plan, the DSM surcharge will be assessed on a per kWh basis for residential customers and on a percentage of bill basis for non-residential customers. The current DSM surcharge for residential customers will be reset from $0.001249 per kWh to $0.000443 per kWh upon the effective date of the new rates in this case.

7.9 Nothing in the Plan is intended to bind the Commission to any specific EE policy or standard, but merely sets up the method of recovery for investments in EE for any EE policy or standard established by the Commission.

VIII. LOST FIXED COST RECOVERY/FIXED RESIDENTIAL RATE OPTION /LARGE CUSTOMER EXCLUSION

8.1 The Signatories support energy efficiency as a low cost energy resource. The Signatories also recognize that, under TEP's current volumetric rate design, the Company recovers a significant portion of its fixed costs of service through kWh sales. Commission rules related to EE and DG require TEP to sell fewer kWh, which, in turn, prevents the Company from being able to recover a portion of the fixed costs of service embedded in its volumetric rates.

8.2 The Signatories also recognize the Commission's interest in directing EE and DG policy. In signing this Agreement, the Signatories intend that an LFCR mechanism with a residential fixed rate option shall be adopted that allows TEP relief from the financial impact of verified lost kWh sales attributable to Commission requirements regarding EE and DG while preserving maximum flexibility for the Commission to adjust EE and DG requirements, either upward or downward, as the Commission may deem appropriate as a matter of policy. Nothing in this Agreement is intended to bind the Commission to any specific EE or DG policy or standard.

8.3 The Signatories propose that the Commission approve an LFCR mechanism that is similar to the LFCR approved for other Arizona utilities. The LFCR shall recover a portion of distribution and transmission costs associated with residential, commercial and industrial customers when sales levels are reduced by EE and DG. It shall not recover lost fixed costs attributable to generation and to other potential factors, such as weather or general economic conditions.

8.4 The LFCR will have a 1% year-over-year cap. The annual 1% year over year cap is based on total applicable TEP retail revenues (i.e., average bills for customers shall not increase by more than 1%). Any amount in excess of the 1% cap will be deferred for collection consistent with the LFCR Plan of Administration. The amount of the cap level set herein shall be evaluated in TEP's next rate case.

8.5 The LFCR mechanism shall not apply to large light & power, water pumping or lighting customers, as delineated in the LFCR Plan of Administration. However, rate design for these customer classes shall be such that they pay their fair share of fixed costs through their monthly minimum and/or demand charge.

8.6 Residential customers shall have a fixed LFCR rate option providing the opportunity to elect an optional higher monthly service charge, graduated by kWh monthly usage. That option is attached hereto as Attachment E. The optional monthly service charge will be incorporated into each residential rate schedule to provide customers with the maximum flexibility to choose the fixed LFCR rate option without requiring a shift to a different rate schedule. The purpose of this fixed LFCR rate option is to replicate, on average, the effects of the LFCR.

8.7 TEP shall seek stakeholder input regarding the development of a customer outreach program to inform and educate customers about the LFCR and shall implement this outreach program by February 1, 2014.

8.8 The LFCR will recover lost fixed cost on a calendar year basis from January 1, 2013 forward and the first LFCR surcharge will not go into effect until July 1, 2014.

8.9 The LFCR Plan of Administration is attached hereto as Attachment F.

IX. ENVIRONMENTAL COMPLIANCE ADJUSTOR SURCHARGE

9.1 TEP will implement an Environmental Compliance Adjustor ("ECA") that will recover environmental compliance costs, subject to a cap equal to 0.25 percent of total TEP retail revenue. TEP will be held responsible for demonstrating that the environmental controls were government-mandated and represented a reasonable and prudent option available to TEP at the time sufficient to meet the environmental requirement. The ECA Plan of Administration is set forth as Attachment G.

X. SPRINGERVILLE UNIT 1

10.1 TEP shall file a report with the Commission no later than July 31, 2014, addressing the status of the Springerville Generating Station ("SGS") lease agreements and the estimated change in TEP's non-fuel revenue requirement at the conclusion of each primary lease term. Specifically, TEP commits to reporting on the following matters:

- The details concerning any commitments made by TEP to purchase SGS Unit 1, or any agreements entered into by TEP to otherwise retain capacity rights to SGS Unit 1, after the end of the primary lease term in January 2015;

- The details concerning any commitments made by TEP to purchase replacement generating resources, or any purchased power agreements entered into by TEP for replacement power, if TEP elects not to purchase or otherwise retain capacity rights to SGS Unit 1 after the end of the primary lease term in January 2015;

- The details concerning any commitments made by TEP to purchase the SGS Coal Handling Facilities, or any agreements entered into by TEP to extend the Coal Handling Facilities lease term, after the end of the primary lease term in April 2015; and

- The estimated non-fuel revenue requirement associated with each of the commitments described above, including the proposed rate treatment of any remaining balance of SGS leasehold improvements.

10.2 Based on the information in the above reporting, the Commission, on its own motion or a recommendation of a Signatory in this case, may require TEP to explain why the Commission should not conduct a proceeding to have TEP's rates reduced accordingly.

XI. PROCUREMENT

11.1 TEP agrees to adopt Staff's proposed modifications to the Company's energy procurement program discussed in the Direct Testimony of Emily Medine, except for the Risk Manager recommendation. The adopted modifications are set forth in Attachment H.

XII. LOW INCOME PROGRAMS

12.1 TEP will limit a typical Lifeline customer's increase to an amount that is generally reflective of the average monthly dollar increase of a standard R-01 customer. The anticipated bill impacts for Lifeline customers are set forth in Attachment I.

12.2 The PPFAC rate and DSM surcharge shall apply to Lifeline customers, and the currently frozen rates shall no longer be portable.

12.3 In compliance with Decision No. 59594 (March 29, 1996), TEP set up a LIFE Fund of $4.5 million. The annual interest from the LIFE Fund was used for the benefit of low-income customers. The Signatories agree that the LIFE Fund should be extinguished and that TEP will make an annual contribution to the Arizona Community Action Association in the amount of $150,000 to fund low-income utility bill assistance programs, commencing on September 1, 2013.

XIII. NOGALES TRANSMISSION LINE

13.1 TEP agrees that, before requesting any rate recovery from the Commission for the cost related to the development of the transmission line between Tucson and Nogales, it will seek recovery of those costs from the Federal Energy

Regulatory Commission ("FERC"). Nothing herein shall preclude Parties from challenging before FERC or the Commission the inclusion of this cost in rates.

XIV. SAN JUAN THERMAL EVENT

14.1 TEP agrees to maintain a separate accounting of all direct costs related to the thermal event at the San Juan mine and that such cost recovery, with the exception of TEP's share of the insurance deductible, be deferred until the insurance settlement has been completed. The estimate of deferred costs is $9.7 million. TEP shall then be eligible to put through all costs in excess of the insurance recovery subject to the standard prudence determination of all fuel costs recovered through the PPFAC. This accounting and regulatory treatment is not intended to set a precedent for future events.

XV. RATE DESIGN

15.1 In addition to the provisions affecting rate design set forth in this Agreement above, rate design shall be addressed as set forth in Attachment J.

15.2 The rate design portion of this Agreement shall remain open until July 1, 2014, to allow for the possible adjustment of specific tariffs to correct for unanticipated customer rate impacts that are determined to be inconsistent with the public interest. Any tariff changes will not have the effect, in the aggregate, of reducing TEP's non-fuel revenue requirement.

XVI. RULES AND REGULATIONS

16.1 TEP's revised Rules and Regulations shall be as agreed to between the Company and Staff. The final version of the Rules and Regulations will be attached to the Company's testimony in support of the Agreement.

XVII GREENWATTS TARIFF AND STATEMENT OF CHARGES

17.1 TEP's GreenWatts tariff is eliminated.

17.2 TEP's revised Statement of Charges is set forth in Attachment K.

XVIII. QUALITY OF SERVICE

18.1 TEP agrees to: (i) continue to evaluate TEP's reliability on the basis of the distribution indices being maintained at present levels and (ii) initiate a study within 180 days of the effective date of the approval of this Agreement to examine potential loss reductions and the costs required to convert 4.16 kV circuits to 13.8 kV.

18.2 TEP agrees to meet with Staff within 180 days of the effective date of the approval of this Agreement to address: (i) potentially increasing the pace of upgrading critical circuits in need of preventative maintenance; (ii) establishing a routine of periodic load-flow analysis of its system and confirming the accuracy of utilized model; and (iii) equip feeder circuits with meters or other equipment so that power information can be relayed to Energy Management Service ("EMS") through Supervisory Control and Data Acquisition ("SCADA") to determine losses on a circuit-by-circuit basis.

XIX. COMPLIANCE MATTERS

19.1 TEP's request for elimination of reporting requirements, as set forth in the Direct Testimony of Craig A. Jones at pages 76-81, shall be approved with the exception of: (i) the reporting requirements under the Commission's Retail Electric Competition Rules (A.A.C. R14-2-1601 et seq.) and (ii) the Cost Containment Report pursuant to Decision No. 59594 (March 29, 1996). The reporting requirements that are eliminated or modified are set forth in Attachment L.

XX. ADDITIONAL SETTLEMENT PROVISIONS

20.1 With respect to the retail space (approximately 12,000 square feet) at the Company's headquarters building, TEP will in its next rate case propose to treat the retail space in a similar manner as set forth in Attachment A.

20.2 Net Operating Losses: Within 60 days following the final decision in Docket No. E-01933A-12-0291, TEP will make a filing proposing the Commission open a generic docket to address the appropriate accounting treatment of Net Operating Losses (NOLs) in future rate cases.

20.3 Depreciation Reserves: In recognition of RUCO's excess depreciation concerns, TEP agrees to the following: (a) If TEP makes any filing with the Commission related to the early retirement of any production asset, TEP will propose that any then-existing excess depreciation reserve for Production Plant will be applied to the unrecovered book value of the retiring asset and (b) TEP will propose in its next rate case that the remaining excess Production Plant depreciation, if any, after the application to the aforementioned early asset retirement will be amortized over 15 years.

20.4 Capital Expenditures for Distribution Plant: TEP agrees to meet with RUCO and Staff once a year for the next 3 years to discuss TEP's capital expenditures, planning horizons, and related planning (reconciled with TEP's IRP) for the upcoming year. TEP will provide the capital expenditure details and supporting information at least one week prior to the scheduled meeting.

20.5 As a compliance item, TEP agrees that it will file in this docket by August 30, 2013 a proposed tariff for interruptible rates. Staff agrees that it will review the filing and docket a Staff Report and Proposed Order for the consideration of the Commission by December 31, 2013.

20.6 In its next general rate case, TEP agrees to propose a rate for customers that take service at 138 kV or higher.

XXI. COMMISSION EVALUATION OF PROPOSED SETTLEMENT

21.1 All currently filed testimony and exhibits shall be offered into the Commission's record as evidence.

21.2 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.

21.3 This Agreement shall serve as a procedural device by which the Signatories will submit their proposed settlement of TEP's pending rate case, Docket No. E-01933A-12-0291, to the Commission.

21.4 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.

21.5 If the Commission fails to issue an order adopting all material terms of this Agreement, any or all of the Signatories may withdraw from this Agreement, and such Signatory or Signatories may pursue without prejudice their respective remedies at law. For purposes of this Agreement, whether a term is material shall be left to the discretion of the Signatory choosing to withdraw from the Agreement. If a Signatory withdraws from the Agreement pursuant to this paragraph and files an application for rehearing, the other Signatories, except for Staff, shall support the application for rehearing by filing a document with the Commission that supports approval of the Agreement in its entirety. Staff shall not be obligated to file any document or take any position regarding the withdrawing Signatory's application for rehearing.

XXII. MISCELLANEOUS PROVISIONS

22.1 This case has attracted a large number of participants with widely diverse interests. To achieve consensus for settlement, many participants are accepting positions that, in any other circumstances, they would be unwilling to accept. They are doing so because this Agreement, as a whole, is consistent with their long-term interests and with the broad public interest. The acceptance by any Signatory of a specific element of this Agreement shall not be considered as precedent for acceptance of that element in any other context.

22.2 No Signatory is bound by any position asserted in negotiations, except as expressly stated in this Agreement. No Signatory shall offer evidence of conduct or statements made in the course of negotiating this Agreement before this Commission, any other regulatory agency, or any court.

22.3 Neither this Agreement nor any of the positions taken in this Agreement by any of the Signatories may be referred to, cited, and/or relied upon as precedent in any proceeding before the Commission, any other regulatory agency, or any court for any purpose except to secure approval of this Agreement and enforce its terms.

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

22.5 Each of the terms of this Agreement is in consideration of all other terms of this Agreement. Accordingly, the terms are not severable.

22.6 The Signatories shall make reasonable and good faith efforts necessary to obtain a Commission order approving this Agreement. The Signatories shall support and defend this Agreement before the Commission. Subject to Paragraph 21.5 above, if the Commission adopts an order approving all material terms of the Agreement, the Signatories will support and defend the Commission's order before any court or regulatory agency in which it may be at issue.

22.7 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 may also be executed electronically or by facsimile.

ARIZONA CORPORATION COMMISSION
UTILITIES DIVISION STAFF

By______________________________

Title______________________________

Date______________________________

TUCSON ELECTRIC POWER COMPANY

By______________________________

Title______________________________

Date______________________________

22.7 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 may also be executed electronically or by facsimile.

ARIZONA CORPORATION COMMISSION
UTILITIES DIVISION STAFF

By____________________

Title Utilities Division Director

Date 2-4-13

TUCSON ELECTRIC POWER COMPANY

By____________________

Title President

Date February 4, 2013

Signatory to February 4, 2013 Tucson Electric Power Company Settlement Agreement

Docket No. E-01933A-12-0291

Residential Utility Consumer Office

By ______________________

Title Director RUCO

Date 2/4/2013

Signatory to February 4, 2013 Tucson Electric Power Company Settlement Agreement
Docket No. E-01933A-12-0291

David Godlewski

Southern Arizona Home Builders Association

By__________________

Title President

Date 1/4/13

Signatory to February 4, 2013 Tucson Electric Power Company Settlement Agreement

Docket No. E-01933A-12-0291

KROGER CO.

By [signature]

Title Attorney

Date 2-4-13

Signatory to February 4, 2013 Tucson Electric Power Company Settlement Agreement

Docket No. E-01933A-12-0291

Freeport-McMoRan Copper & Gold Inc.

By

C. Webb Crockett
Patrick J. Black
Fennemore Craig, P.C.

Title Attorneys for Freeport-McMoRan Copper & Gold Inc.

Date February 4, 2013

Signatory to February 4, 2013 Tucson Electric Power Company Settlement Agreement

Docket No. E-01933A-12-0291

Arizonans for Electric Choice and Competition

By____________________________________
C. Webb Crockett
Patrick J. Black
Fennemore Craig, P.C.

Title Attorneys for Arizonans for Electric Choice and Competition

Date February 4, 2013

Signatory to February 4, 2013 Tucson Electric Power Company Settlement Agreement
Docket No. E-01933A-12-0291

[PARTY NAME]

By Mona Tierney Lloyd

Title Director, Reg Affairs, EnerNOC

Date 2-4-13

PAGE 2/2 * RCVD AT 2/4/2013 9:48:38 AM [US Mountain Standard Time] * SVR:HQDWPFAX01/7 * DNIS:586 * CSID:5203888412 * DURATION (mm-ss):00-45

Signatory to February 4, 2013 Tucson Electric Power Company Settlement Agreement

Docket No. E-01933A-12-0291

IBEW LOCAL 1116

By [signature]

Title Attorney for IBEW (on behalf of Frank Grijalva, Business Manager)

Date 2/4/13

Signatory to February 4, 2013 Tucson Electric Power Company Settlement Agreement
Docket No. E-01933A-12-0291

Cynthia Zwick

By [signature]

Title

Date FEBRUARY 4, 2013

Signatory to February 4, 2013 Tucson Electric Power Company Settlement Agreement
Docket No. E-01933A-12-0291

ARIZONA INVESTMENT COUNCIL

By [signature]

Title President

Date 2/4/2013

Signatory to February 4, 2013 Tucson Electric Power Company Settlement Agreement
Docket No. E-01933A-12-0291

[Opower Inc.]

By ____________________

Title Attorney

Date 2-4-13

Signatory to February 4, 2013 Tucson Electric Power Company Settlement Agreement
Docket No. E-01933A-12-0291

The Vote Solar Initiative:

By [signature]

Title Attorney for VSI

Date Feb. 4, 2013

Signatory to February 4, 2013 Tucson Electric Power Company Settlement Agreement

Docket No. E-01933A-12-0291

United States Department of Defense and all other Federal Executive Agencies

By ______________________
Kyle J. Smith

Title General Attorney

Date February 5, 2013

Signatory to February 4, 2013 Tucson Electric Power Company Settlement Agreement

Docket No. E-01933A-12-0291

[Southern Arizona Water Users Association]

By [signature]

Title Board President

Date 2-4-13

Signatory to February 4, 2013 Tucson Electric Power Company Settlement Agreement

Docket No. E-01933A-12-0291

Arizona Solar Energy Industries Association

By Mark L Mey

Title Executive Director

Date 2-12-13

Signatory to February 4, 2013 Tucson Electric Power Company Settlement Agreement
Docket No. E-01933A-12-0291

Solar Energy Industries Association

By [signature]

Title Senior Vice President

Date February 13, 2013

ATTACHMENT

"A"

DECISION NO. 73912

TUCSON ELECTRIC POWER COMPANY
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
TEST YEAR ENDED DECEMBER 31, 2011

	As Filed TEP 6/30/12	Settlement 2/4/13	Summary
Original Cost Rate Base - Unadjusted	$1,627,962,142	$1,627,962,142	
Rate Base Adjustments			
Sahuarita - Nogales Transmission Line	11,088,732	-	For purposes of settlement and to be reflected in rates in this proceeding, the Settling Parties agree that recovery will be pursued at the Federal Energy Regulatory Commission.
Leasehold Improvements	(765,060)	(765,060)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Post Test Year Plant	20,441,231	20,441,231	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Post Test Year Plant - Renewable	15,710,443	15,710,443	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Delayed Plant	7,650,854	7,650,854	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Accumulated Deferred ITC	(1,605,208)	(1,605,208)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Accumulated Deferred Income Tax	(126,648,626)	(126,648,626)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Allowance for Working Capital	(34,761,146)	(35,683,128)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Total Adjustments to Rate Base	(108,888,780)	(120,899,494)	
Rate Base	$ 1,519,073,362	$ 1,507,062,648	
Requested Rate of Return	7.74%	7.26%	For purposes of settlement and to be reflected in rates, the Settleing Parties agree that a capital structure of 43.50 % Equity @10.00% and 55.97% Long-Term Debt @ 5.18% and .53% Short-Term Debt @ 1.42% be used.
Required Operating Income OCRB	$117,609,698	$109,412,748	
Fair Value Increment of Rate Base	$761,142,979	$761,136,605	
Fair Value Rate Base (FVRB)	$2,280,216,341	$2,268,199,253	
Proposed FVROR	5.68%	5.05%	
Required Operating Income on FVRB	129,483,528	$114,588,477	
ROR on Fair Value Increment of Rate Base	1.56%	0.68%	The Settling Parties agree to the reduced level of return on the fair value rate base increment for purposes of settlement.

TUCSON ELECTRIC POWER COMPANY
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
TEST YEAR ENDED DECEMBER 31, 2011

	As Filed TEP 6/30/12	Settlement 2/4/13	Summary
Original Operating Income - Unadjusted	$257,751,277	$257,751,277	
Operating Revenue Adjustments			
State Energy Program	(1,254,299)	(1,254,299)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
REST & DSM	(46,633,198)	(46,633,198)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Green Watts	(81,180)	(81,180)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Springerville Unit 3 & 4	(87,568,386)	(80,607,382)	For purposes of settlement and to be reflected in rates the parties agree to adjust the reimbursement of operating expenses to 100%.
Power Supply Management	(641,665)	(641,665)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Customer and Weather Adjustment	(7,922,107)	(7,922,107)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
PPFAC Adjustment	(12,436,902)	(12,176,849)	For purposes of settlement and to be reflected in rates, the Settling Parties agree to adjustments to reflect the current PPFAC rate.
Service Fees & Late Fees	1,109,816	1,109,816	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Customer Care & Billing (CC&B) Allocation	717,619	717,619	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
People Soft Allocation	(64,566)	(64,566)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Building Allocation to Affiliates	506,224	506,224	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Sulfur Credit	-	(5,076,000)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Lime Expense	-	12,879,613	For purposes of settlement and to be reflected in rates, the Settling Parties agree to adjustments that reflect lime expense and sulfur credits as PPFAC includable costs.
Headquarter Return Offset		2,389,000	For purposes of settlement and to be reflected in rates in this proceeding, the Settling Parties agree to include a reduction to TEP's cost of service producing a return "on" its new office building at TEP's cost of debt.
Headquarter Retail Space Rent	-	250,000	For purposes of settlement and to be reflected in rates in this proceeding, the Settling Parties have agreed to assume a rent equivalent to $20.83/square foot on 12,000 square feet of retail space. [Market equivalent $12-$15 per square foot]
Total Adjustments to Operating Revenues	($154,268,644)	($136,604,974)	

TUCSON ELECTRIC POWER COMPANY
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
TEST YEAR ENDED DECEMBER 31, 2011

	As Filed TEP 6/30/12	Settlement 2/4/13	Summary
Operating Expense Adjustments			
Implementation Cost Regulatory Asset	(3,553,210)	(3,553,210)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
State Energy Program	(1,253,688)	(1,253,688)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
REST & DSM	(34,129,577)	(34,129,577)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Green Watts	(28,094)	(28,094)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Springerville Units 3 & 4	(66,126,339)	(66,126,339)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Revenue form Sale of S02 Allowances	1,212	1,212	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Sales for Resale	(128,262,147)	(128,262,147)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Power Supply Management	(217,252)	(217,252)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
PPFAC Adjustment	168,304,294	168,564,347	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Sahuarita - Nogales Tran Line Amortization	2,982,638	-	For purposes of settlement and to be reflected in rates in this proceeding, the Settling Parties agree that recovery will be pursued at the Federal Energy Regulatory Commission.
Generating Facilities - Operating Lease	(3,148,432)	(3,148,432)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Springerville Unit 1	41,014,390	41,000,514	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Overhaul & Outage Normalization	1,191,868	(1,322,100)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Payroll Expense	2,898,605	2,898,605	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Payroll Tax Expense	193,390	193,390	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Pension & Benefits	200,143	200,143	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Retiree Medical	1,235,251	1,235,251	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Incentive Compensation	2,014,330	(80,108)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Rate Case Expense	192,187	(25,998)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Injuries and Damages	599,268	599,268	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.

TUCSON ELECTRIC POWER COMPANY
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
TEST YEAR ENDED DECEMBER 31, 2011

	As Filed TEP 6/30/12	Settlement 2/4/13	Summary
Membership Dues	(79,913)	(191,016)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Bad Debt Expense	639,648	639,648	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
CC&B Allocation	1,217,949	1,217,949	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
People Soft Allocation	(187,570)	(187,570)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Depr. & Amort. Expense Annualization	(3,197,238)	(3,197,238)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Non-Recurring	(1,492,550)	(1,492,550)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Property Tax	2,305,832	848,741	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Asset Retirement Obligation	(299,189)	(299,189)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Building Expense Annualization	286,055	286,055	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Lime Expense	1,246,043	1,246,043	reflected in rates in this proceeding. The net Lime expense and sulfur credit amount in O&M were offset and reflected as PPFAC includable costs.
Credit Support		21,000	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Post Test Year Depreciation		1,520,175	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Income Tax	(23,564,462)	(14,198,335)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
OATT	90,028,056	90,028,056	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Directors and Officers Liability Insurance		(289,320)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Day Nite / General Corporate Advertising		(13,061)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Total Adjustments to Operating Expense	$51,011,498	$52,485,173	
Total Net Adjustments	($205,280,142)	($189,090,147)	
Adjusted Operating Income	$52,471,135	$68,661,130	
Operating Income Deficiency	$77,012,393	$45,927,347	
Gross Revenue Conversion Factor	1.6590	1.6590	
Increase in Gross Revenue Requirement	$127,760,018	$76,194,257	

ATTACHMENT

"B"

Tucson Electric Power Company
Test Period Ending December 31, 2011
Revenue Allocation - Test Year Adjusted
Attachment B

Line No.	Description	Total Adjusted TY Revenues	Total Fuel Revenue Increase	Total Non-Fuel Revenue Increase	Total Proposed Revenues	Percent Allocated
1	Residential	$363,572,522	$11,968,386	$36,283,601	$411,824,508	13.3%
2	Small General Service	223,685,672	9,960,816	17,646,762	251,293,250	12.3%
3	Water Pumping	7,355,490	481,929	554,386	8,391,806	14.1%
4	Large General Service	100,687,806	4,369,445	9,861,330	114,918,581	14.1%
5	Large Light and Power	114,163,922	4,502,721	11,608,894	130,275,537	14.1%
6	Lighting	3,936,000	316,595	239,336	4,491,931	14.1%
7	Subtotal	$813,401,411	$31,599,892	$76,194,310	$921,195,613	13.3%

ATTACHMENT

"C"

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. 70628 (December 1, 2008) and amended by the Commission in Decision No. XXXXX (date). ~~The PPFAC provides for the recovery of fuel and purchased power costs from the date of Decision No. XXXXXthat 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. ~~70628~~ XXXXX set the base cost at $0.032335 per kWh ~~at $0.02896 per kWh~~ effective on ~~December 1, 2008~~[date].

~~Fixed CTC True Up Revenues – The incremental revenue that was collected as a result of retaining the Fixed CTC in place and maintaining Standard Offer rates, pursuant to Decision No. 69568.~~

Brokerage Fees – The costs attributable to the use of brokers recorded in Federal Energy Regulatory Commission ("FERC") Account 557.

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.~~

Lime Costs (FERC Account 502) – The costs recorded for lime used to remove sulfur compounds formed during coal combustion.

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. Wholesale sales with a duration of one year or greater are also included.

~~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. 70628 and amended 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. 70628) 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 that serves TEP's retail customers ~~that is served by TEP and~~ located within the TEP control area.

Short Term Sales – Wholesale sales with~~for~~ durations of less than one year 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 with durations of less than one year 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~~.

SO₂ 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 Brokerage Fees~~Commissions~~ paid.

Sulfur Credits – Credits received by TEP related to coal sulfur content that offset the cost of chemicals used to remove sulfur compounds formed during coal combustion.

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. 70628 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 an estimate~~a proposed calculation~~ of the components for the following April's PPFAC rate. This filing shall be accompanied by supporting information as Staff determines to be required. TEP will update~~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.

Credits to the PPFAC

The following will be credited to the PPFAC:

1. All revenues from Short Term Sales; ~~will be credited against fuel and purchased power costs.~~
2. Ten percent of the net positive margins realized by TEP during the PPFAC year on its Wholesale Trading Activities;
3. ~~will be credited against fuel and purchased power costs.~~ One hundred (100%)~~Fifty~~ percent of the margins realized by TEP on SO_2 Allowance Sales (net of brokerage fees);
4. ~~will be credited against fuel and purchased power costs.~~All Sulfur Credits received by TEP; and
5. ~~1.~~The sale of renewable energy credits that do not flow through the Renewable Energy Standard Tariff.

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

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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~~ update the October filing. This update~~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 before the PPFAC rate would go into effect. In addition to the February 1 update filing, TEP 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.,~~the Forward Component and the True-Up Component. The PPFAC rate shall be applied to customer bills. Upon Commission approval, T~~the~~ proposed PPFAC rate (as amended by the updated February 1 filing) shall go into effect on April 1. 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 approved 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. CALCULATION OF THE FIXED CTC TRUE-UP REVENUE CREDIT*~~

~~In addition to the True-Up Component as described in the preceding paragraph, Commission No. 70628 requires that all Fixed CTC True-Up Revenues be credited in their entirety to the ratepayers by means of a credit to the PPFAC.~~

~~The Fixed CTC Revenues shall be credited against PPFAC eligible costs in a manner that keeps the PPFAC rate at zero until the Fixed CTC True-UP Revenues are fully credited. Once the annual PPFAC Rate has been calculated in accordance with Section 4 of this Plan of Administration, the Fixed CTC Revenue Credit shall be equal and opposite of the PPFAC Rate until the Fixed CTC Revenues have been fully credited back to the ratepayers.~~

~~A Tracking Account shall be used to track the Fixed CTC Revenue Credit until the account balance reaches zero.~~

56. 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 upon Commission approval.

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.

67. 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).

TEP agrees to pay the cost of biennial audits of its PPFAC by an outside auditor retained by the Commission.

78. SCHEDULES

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

Schedule 1	PPFAC Rate Calculation
Schedule 2	PPFAC Forward Component Rate Calculation
Schedule 3	PPFAC Forward Component Tracking Account
Schedule 4	PPFAC True-Up Component Rate Calculation
Schedule 5	PPFAC True-Up Component Tracking Account

89. 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 and that there have been no changes to the Allowable Costs recovered through the PPFAC without Commission approval. These monthly reports shall be due within 45~~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 45~~30~~ days of the end of the reporting period. All of these additional reports must 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. 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.

D. 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 Purchase 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~~10. 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/Credits

- Brokerage Fees recorded in FERC Account 557
- Lime costs recorded in FERC Account 502
- Sulfur credits recorded in FERC Account 501 or 502 (whichever FERC requires)

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

No other costs or credits are allowed without~~ne without pre~~ approval from the Commission in an Order.

Tucson Electric Power Company
Purchased Power and Fuel Adjustment Clause
Monthly Information Filing
Proposed 20xx & 20xx PPFAC Rate Filing

Schedule 1	Projected Rate Calculation effective April 1, 20xx
Schedule 2	Projected PPFAC Forward Component Rate Calculation Effective April 1, 20xx
Schedule 3	Projected Forward Component Tracking Account Balance
Schedule 4	Projected PPFAC True-Up Component Rate Calculation Effective April 1, 20xx
Schedule 5	Projected True-Up Component Tracking Account Balance
	Lime Cost Support
	Sulfur Credit Support
	Brokerage Cost Support
	Forecast

Tucson Electric Power Contact Information

Toby Voge (520) 745-3332
Senior Director, Tucson Electric Power

TUCSON ELECTRIC POWER COMPANY
Schedule 1
Purchased Power and Fuel Adjustment Clause (PPFAC) Rate Calculation
($/kWh)

Line No.	PPFAC Rate Calculation		Current 4/1/20xx	Proposed 4/1/20xx	Increase / (Decrease) $.000000/kWh	%
1	Forward Component Rate (Sch. 2, L12) [1]					
2	True-Up Component Rate (Sch. 4, L5) [2]					
3	PPFAC Rate April 1, 20xx	(L1+L2)				
4	Average Base Rate April 1, 20xx [3]					
5	Average Total Rate April 1, 20xx	(L3+L4)				

Notes:

[1] TEP PPFAC effective April 1, 20xx, and proposed 20xx rate

[2] A Historical Component is a true-up related to respective prior period PPFAC activity.

[3] Average Base Rate as defined in Decision No.XXXXX

A

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 4/1/20xx	Proposed 4/1/20xx	Increase / (Decrease) $ Values	Increase / (Decrease) %
1	Projected PPFAC Fuel and Purchased Power Costs 1				
2	Projected Short Term Sales Revenue Credit [2]				
3	Projected Wholesale Trading Activities Credit 3				
4	Projected SO2 Allowance Sales Credit [4]				
5	Net Fuel and Purchased Power Cost (L1+ L2+L3 +L4)				
6	Projected Native Load Energy Sales (kWhs)				
7	Projected Average Net Fuel Costs $/kWh (L5/L6)				
8	Base Cost of Fuel and Purchased Power $/kWh				
9	Difference between Projected Cost & Base Cost (L7-L8)				
10	Forward Component Costs (L6*L9)				
11	Projected Energy Sales (kWh)				
12	Forward Component Rate $/kWh (L10/L11)				

Notes:

1 Includes Sulfur Credits, Lime Costs, and Brokerage Costs per Commission Decision No. xxxxx

2 Short Term Sales revenues are credited at 100% as approved by the Commission in Decision No. 70628.

3 10% of Wholesale Trading Activities credited against Fuel and Purchased Power Costs as approved by the Commission in Decision No. 70628.

4 100% of SO2 Allowance Sales credited against Fuel and Purchased Power Costs per Commission Decision No. xxxxx

B

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)

Line No.		Actual data								Forecasted Data	
		Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13
1a	TU Beginning Balance as of Apr. 1, 2009 [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 Application TU (L4 x L5) [4]										
7	Monthly Interest (Line 3 * 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
[3] Sales amounts are for energy billed beginning with the first billing cycle of April 20xx. Retail Billed Sales excludes low income customers not subject to the PPFAC Rate.
[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. As of 1/3/2012 0.00%

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

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TUCSON ELECTRIC POWER COMPANY

Lime Costs

el Imbalance Tracking Account - PPFAC Rate in effect Month/Day/Year

($ in thousands; Rates in $/kWh)

	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13
Forecasted Tons								
Forecasted $/Ton								
Forecasted Cost								
Forecasted Generation								
Expected $/MWh								
Actual Tons								
Actual Costs								
Actual Generation								
Actual $/MWh								

DECISION NO. 73912

TUCSON ELECTRIC POWER COMPANY

Sulfur Credit

tel Imbalance Tracking Account - PPFAC Rate in effect Month/Day/Year

($ in thousands; Rates in $/kWh)

	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
Forecasted Tons/mmbtu									
Forecasted $/Ton									
Forecasted Cost									
Forecasted Generation									
Expected $/MWh									

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Docket No. E-01933A-12-0291

TUCSON ELECTRIC POWER COMPANY

Brokerage Costs

Fuel Imbalance Tracking Account - PPFAC Rate in effect Month/Day/Year

($ in thousands; Rates in $/kWh)

	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13
Costs							

TEP MONTHLY PPFAC REPORT

Ascend Analytics
PowerSimm Planner
TEP
Monthly

	2012-08	2012-09	2012-10	2012-11	2012-12	2013-01	2013-02	2013-03	2013-04	2013-05	2013-06	2013-07	2013-08	2013-09	2013-10	2013-11	2013-12	2014-01	2014-02	2014-03
TEP PPFAC COSTS $000																				
Fuel Expense																				
Purchase Power Expense																				
Total Fuel & Purchase Power																				
Renewable Delta																				
Firm Purchase Power Demand Charges																				
Transmission Wheeling Charges																				
Net Position on Financial Gas Hedges																				
Total PPFAC Eligible Costs Excl Wholesale																				
FIRM LOAD (MWh)	2012-08	2012-09	2012-10	2012-11	2012-12	2013-01	2013-02	2013-03	2013-04	2013-05	2013-06	2013-07	2013-08	2013-09	2013-10	2013-11	2013-12	2014-01	2014-02	2014-03
Retail Load with System Losses																				
Firm Wholesale Load																				
Total Firm Load Obligations																				
SALES (MWh)	2012-08	2012-09	2012-10	2012-11	2012-12	2013-01	2013-02	2013-03	2013-04	2013-05	2013-06	2013-07	2013-08	2013-09	2013-10	2013-11	2013-12	2014-01	2014-02	2014-03
Retail Sales																				
System Sales																				
Total Sales																				
LOSSES (MWh)	2012-08	2012-09	2012-10	2012-11	2012-12	2013-01	2013-02	2013-03	2013-04	2013-05	2013-06	2013-07	2013-08	2013-09	2013-10	2013-11	2013-12	2014-01	2014-02	2014-03
Retail Losses																				
Firm Losses																				
Total Losses																				
SALES WITH LOSSES (MWh)	2012-08	2012-09	2012-10	2012-11	2012-12	2013-01	2013-02	2013-03	2013-04	2013-05	2013-06	2013-07	2013-08	2013-09	2013-10	2013-11	2013-12	2014-01	2014-02	2014-03
Retail Sales																				
Long Term Wholesale Sales																				
Total System Losses																				
Total Sales with Losses																				
JURISDICTIONAL ALLOCATION	2012-08	2012-09	2012-10	2012-11	2012-12	2013-01	2013-02	2013-03	2013-04	2013-05	2013-06	2013-07	2013-08	2013-09	2013-10	2013-11	2013-12	2014-01	2014-02	2014-03
Energy Ratio																				
TOTAL PPFAC ELIGIBLE COSTS JURISDICTIONAL ALLOCATION	2012-08	2012-09	2012-10	2012-11	2012-12	2013-01	2013-02	2013-03	2013-04	2013-05	2013-06	2013-07	2013-08	2013-09	2013-10	2013-11	2013-12	2014-01	2014-02	2014-03
Thermal Production - FERC 501 and FERC 547																				
Purchased Power - Energy - FERC 555																				
Purchased Power - Demand - FERC 555																				
Transmission of Electricity by Others - FERC 565																				
Total PPFAC Eligible Costs Allocated to Retail																				
Less Wholesale Sales Revenue																				

G:\Regulatory Counsel\Shared\2012 TEP RATE CASE\Settlement Agreement Documents\Settlement Agreement & Attachments\Attachments to Settlement Agreement\PPFAC POA & Attachments\TEP-POA PPFAC Schedules Jan 31

ATTACHMENT "D"

Tucson Electric Power Company
Energy Efficiency Resource Plan
Plan of Administration

Table of Contents

Exhibits

1. General Description

This document describes the Plan of Administration ("POA") for the Energy Efficiency Resource Plan ("EERP") approved for Tucson Electric Power Co. ("TEP" or "Company") by the Arizona Corporation Commission ("Commission") on XXXX, 2013 in Decision No. XXXX ("Decision"). The EERP mechanism provides for the recovery of allowable costs related to Demand Side Management/Energy Efficiency Programs ("DSM/EE") as a capital investment, setting recovery of the asset over a five-year term where TEP recovers the revenue requirements from carrying costs and regulatory asset amortization in cost-effective DSM/EE programs through the Demand Side Management Surcharge ("DSMS"), as described within this POA.

2. Definitions

Amortize – The process of ratably distributing a previously capitalized cost to expense over a designated period.

Avoided Cost – The avoided cost is the marginal cost to produce one more unit of energy. The avoided cost consist of two components: avoided cost of energy and avoided cost of capacity.

> TEP's avoided cost of energy or marginal energy cost is determined using the Resource Planning Hourly Economic Dispatch Model.
>
> TEP's avoided cost of capacity is determined through TEP's long-term planning modeling of capacity. The plan for meeting capacity needs is determined on both economics and reliability. Future capacity costs include market purchase power capacity, transmission upgrades and capacity build options.

Carrying Costs – Costs recovered through the DSMS charge include a return on EERP Program Investment Base[1] based on TEP's Weighted Average Cost of Capital ("WACC") approved by the Commission in Decision No. XXXXX.

Combined Heat and Power ("CHP") – Combined heat and power, which is using a primary energy source to simultaneously produce electrical energy and useful process heat.

Cost-Effective – The result of an action or series of actions where the total incremental benefits from a DSM/EE measure or DSM/EE program exceed total incremental costs over the life of the DSM/EE measure.

Demand Savings – The load reduction, measured in kW, occurring during a relevant peak period or periods as a direct result of energy efficiency and demand response programs.

Demand Response ("DR") – Modification of customer's electricity consumption patterns, affecting the timing or quantity of customer demand and usage, achieved through intentional actions taken by an affected utility or customer because of changes in prices, market conditions, or threats to system reliability.

[1] Program Investment Base as delineated in Section 6.A.

Demand Side Management ("DSM") – Reduction of electricity use through the implementation and maintenance of Company-sponsored measures, programs or plans.

DSM Measure – Any material, device, technology, educational program, pricing option, practice, or facility alteration designed to result in reduced peak demand, increased energy efficiency, or shifting of electricity consumption to off-peak periods and includes CHP used to displace space heating, water heating, or another load.

DSM Program – One or more DSM measures provided as part of a single offering to customers.

Demand Side Management Surcharge ("DSMS") – A Commission-approved provision in TEP's rate schedule allowing TEP to change certain rates through a surcharge, in an established manner, when changes in specific costs and charges are incurred by TEP.

Energy Efficiency ("EE") – The production or delivery of an equivalent level and quality of end-use electric service using less energy, or the conservation of energy by end-use customers.

Energy Efficiency Programs – Any program that is specifically designed to reduce energy use and/or provide some non-coincident and coincident peak demand savings.

Energy Savings – The reduction in a customer's energy consumption directly resulting from a DSM/EE program, expressed in kWh, at the generator.

Energy Efficiency Standard – The Arizona Electric Energy Efficiency Standards, Title 14, Chapter 2, Article 24 of the Arizona Administrative Code.

Incentives – Financial payments, goods, or services offered by a utility to promote energy and related cost savings including, but not limited to, cash rebates or financial payments, advanced financing of project costs, design and implementation of utility related projects, energy management services, facilities alterations, installation of technologies and energy savings devices, or water conservation devices.

Incremental Cost – Additional expenses of DSM/EE measures, relative to baseline.

Measurement, Evaluation, and Research ("MER") – The performance of studies and activities aimed at determining the effects of an energy efficiency program, which may include data collection, monitoring, and analysis associated with the calculation of energy and demand savings from measures or projects, and including research necessary to inform the evaluation of existing EE programs and the design of new EE programs.

Non-Energy Benefits – Non-energy benefits (or non-market benefits) are the improvements in societal welfare that are not bought or sold. These benefits are any program implementation or participation effect that is other than the direct energy savings effects associated with an energy efficiency, resource acquisition, or resource procurement program. Some examples may include: reduced water consumption, reduced emission and environmental benefits in a building, secondary economic impacts from low income programs, health and safety, job creation, improved comfort, indoor air quality, longevity of equipment, improved worker productivity, and worker retention.

Program Costs – The expenses incurred as a result of developing, marketing, implementing, administering, and evaluating Commission-approved DSM/EE programs.

Regulatory Asset – A capitalized cost that would otherwise be accounted for as an expense, but for its inclusion in a Commission approved cost recovery mechanism providing for such costs to be deferred and then transferred to expense and recovered through basic service rates or a specific surcharge in effect for a designated period.

Societal Test – A cost-effectiveness test of the net benefits of DSM/EE programs that starts with the Total Resource Cost Test, but includes non-energy benefits and costs to society.

Total Resource Cost Test – A cost-effectiveness test that measures the net benefits of a DSM/EE program as a resource, including incremental measure costs, incremental affected utility costs, and carrying costs as a component of avoided capacity cost, but excluding incentives paid by affected utilities and non-market benefits to society.

3. Annual Energy Efficiency (EE) Investment

Program investments will be the sum of actual costs for all DSM/EE programs, plus allowable costs outlined in section 7. Actual costs incurred, after program savings have been verified through the MER process, will be deemed to be allowable investments for recovery.

4. Cost-effectiveness

TEP will invest in existing DSM/EE programs and measures that have been previously approved by the Commission and implemented by TEP. In addition, TEP will invest in and implement new EE measures and programs only once it is shown that they produce a benefit/cost ratio greater than one, resulting from using the Societal Test.

A new EE measure or program that passes the Societal Test as defined herein will be filed for Commission approval in an annual EE Implementation Plan.

5. Annual Implementation Plans

TEP will file annual Implementation Plans by June 1 of each year. The Implementation Plan approved by the Commission shall remain in effect until further order of the Commission. The Company will propose (at a minimum) in their annual Implementation Plans:

- New programs and measures, if any
- Societal test results and models
- Proposed Budgets
- Annual savings
- Cost per kWh (based on lifetime savings)
- Targets for annual savings and costs per kWh

Based on the Implementation Plan filed by June 1st, Staff will file a Staff Report and proposed order by November 15th of same year.

6. Revenue Requirement

The following discussion provides inputs and methodologies for each of the terms in the capitalization model. The revenue requirement will be determined by applying a 5-year amortization schedule to actual DSM/EE Costs for the previous calendar year. Exhibit 1 provides an example of what the revenue requirement worksheets would look like over the next four years. Investment dollars are for illustration purposes only.

A. Program Investment Base

Program Investment Base will be equivalent to the actual DSM/EE spending after providing documentation through the MER reports. For purposes of computing the amortization expense and the return components of the program revenue requirement that will underlie the DSMS, a program investment base will be comprised of a regulatory asset for which the actual program spending will be accumulated. Upon implementation of a specific program, all actual program costs will be charged to the regulatory asset. Deducted from the regulatory asset will be the accumulated amortizations based on recovery of all actual expenses at a rate of 20% for each of the five years. In addition, the net program investment base will be reduced by Accumulated Deferred Income Taxes reflecting the book-tax timing difference created by all program expenditures being currently deducted for tax, but deferred and amortized over five years for accounting purposes. Based on the previous year's actual DSM/EE spending, the revenue requirement will be calculated as the sum of the average of the beginning and end of year net investment balances, multiplied by the allowed rate of return, plus the regulatory asset amortization.

Should the EE Resource Plan be discontinued at a future date, TEP will be permitted to recover the balance remaining in the regulatory asset through continued use of the DSMS in existence at the time and until such time that the entire balance is collected. In connection with the discontinued EE Resource Plan, TEP would provide final documentation reconciling all differences between program budgets and actual costs incurred producing any unrecovered balance remaining in the regulatory assets at the end of the last funding cycle.

B. Carrying Costs

TEP's return on the EE Resource Plan investments will be based on TEP's WACC as approved by the Commission in Decision No. XXXXX (DATE). TEP's investment in EE/DSM will accrue Carrying Costs from the date expenditures are incurred.

C. Annual Recovery of Program Investment Base

TEP will recover the allowable costs associated with the EERP if actual results of the EE/DSM investments achieve a minimum annual portfolio level savings (kWh) and do not exceed the maximum portfolio level cost ($ per kWh) (based on lifetime savings) set annually in implementation plans as approved by the Commission.

Beginning in 2013 the minimum annual portfolio level savings shall be set at 84,024,000 kWh and will not exceed a maximum portfolio level cost of $0.02208 per kWh. These levels will remain in effect until further order of the Commission.

For the purposes of this calculation Demand Response or Direct Load Control Programs will be set at the level of saving credit specified in A.C.C. R-14-2-2404. C. (Peak reduction capability will be converted to an annual energy saving equivalent based on an assumed 50% annual load factor and not to exceed 10% of the energy efficiency standard).

7. Demand Side Management Surcharge

A. Rate Schedule Applicability

The DSMS shall be applied monthly to every rate schedule unless exempted by order of the Commission. A DSMS schedule is included in Exhibit 2 and shall be updated with Commission Order.

A self-direction option exists for qualifying customers of sufficient size in which the amount of money paid by each qualifying customer toward DSM costs is tracked for the customer and made available for use by the customer for approved DSM investments. Details on the self-direction option are included in Exhibit 3.

B. Allowable Costs

Allowable Costs include: program implementation; rebates and incentives; training and technical assistance; consumer education; marketing; planning and administration; measurement, evaluation and research; new program development and analysis; any software development required for tracking and reporting of EE and DR programs; and any other expenses required to design and implement cost-effective EE and DR programs. All program costs will be charged to the appropriate regulatory asset after spending occurs and savings are verified through MER activities as previously described. As such amounts are amortized, they will be charged to FERC Account 908, Customer Assistance Expense or other appropriate accounts as required by the FERC Uniform System of Accounts. Amortization expense and revenues will be recorded monthly based on each month's retail sales volumes.

C. Determination of True-up

As delineated in Exhibit 2, the DSMS that will take effect upon the effective date of Decision No. XXXXX (DATE) will be set to include all historical unrecovered DSM expenses incurred by TEP up to the time of the effective date of this Order, which is estimated to be $4 million and will be recovered over a 12 month period. Any amount over or under collected by TEP's voluntary March 1, 2013 resumption of projects, shall be included as determined under this Plan in the March 1, 2014 DSMS reset.

On March 1 of each year following the effective date of this order, TEP will file a DSMS reset request that will include the revenue requirements based upon all allowable investments from the

DECISION NO. 73912

previous program year(s). The new DSMS will be effective June 1 of each year, upon Commission approval.

D. Determination of the Surcharge

The revenue requirements (under this Plan) determined by the sum of Carrying Costs and regulatory asset amortization for each program year will be divided by the forecasted energy sales for the recovery time period to determine the $/kWh DSMS for residential customers and a percentage of bill for non-residential customers. Exhibit 5 shows an example schedule for determining the total annual revenue requirements used for calculating the DSMS for the first four years of funding.

On March 1, 2014, TEP will file a DSMS reset request for purposes of recovering investments under the EERP from March 1, 2013 through December 31, 2013. The DSMS will be calculated based upon the following formula:

$$\text{DSMS} = \frac{\text{RR1}}{\text{Sales}}$$

Where:

RR1	=	First year of 2013 revenue requirement is equal to expenses from March 1, 2013 above historical spending levels through the effective date of this order in excess of the estimated $4 million under recovery from prior periods, plus expenses after the effective date of Decision No. XXXXX through December 2013.
Sales	=	Forecasted energy (kWh) sales under applicable rate schedules during the period in which the DSMS will be effective.

On March 1, 2015, TEP will file a DSMS reset request for purposes of recovering investments under the EERP for the 2014 program year (January 1, 2014- December 31, 2014). The DSMS will be calculated based upon the following formula:

$$\text{DSMS} = \frac{\text{RR2}}{\text{Sales}}$$

Where:

RR2	=	First year of 2014 revenue requirement plus the second year of 2013 revenue requirement.
Sales	=	Forecasted energy (kWh) sales under applicable rate schedules (as defined above) during the period in which the DSMS will be effective.

All subsequent March 1st filings for a DSMS reset will follow the procedure outlined above.

The proposed DSMS Tariff is provided in Exhibit 4.

8. DSM/EE Reports

In accordance with A.A.C. R14-2-2409, the Company will provide a previous year progress report to the Commission by March 1st and a current mid-year status report by September 1st of each year. The compliance filings and dates contained in this POA and Decision No. XXXXX (DATE) supersede the requirements contained in previous Commission Orders.

EERP POA –Exhibit 1 – Example Revenue Requirements

2013 Revenue Requirement

Year 2013 (Mar '13 - Dec '13)	Capitalization of EE Investments						
	[redacted]	Original Cost					
	5	Asset Life					
	39.6%	Income Tax Rate					
	7.74%	Nominal Return					
	10.98%	Pre-tax Return					
	6.64%	After-tax Return					
		Capital Structure:					
	54.00%	Debt					
	46.00%	Equity					
		Short-Term Debt					
		Cost of Capital:					
	5.18%	Debt					
	10.75%	Equity					
		Short-Term Debt					
		2014	2015	2016	2017	2018	2019
	0	1	2	3	4	5	6
Regulatory Asset Amortization		$ 2,908,915	$ 2,908,915	$ 2,908,915	$ 2,908,915	$ 2,908,915	$ -
Tax depreciation	$ -	$ 14,544,577	$ -	$ -	$ -	$ -	$ -
Net book basis (end of year)	$ -	$ 11,635,662	$ 8,726,746	$ 5,817,831	$ 2,908,915	$ -	$ -
Tax basis (end of year)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ADIT (end of year) ((book basis minus tax basis) times t	$ -	$ 4,604,231	$ 3,453,174	$ 2,302,116	$ 1,151,058	$ -	$ -
Long-term debt balance (end of year)	$ -	$ 3,796,972	$ 2,847,729	$ 1,898,486	$ 949,243	$ -	$ -
LT Debt Interest		$ 237,367	$ 172,098	$ 122,927	$ 73,756	$ 24,585	$ -
Rate Base, end of year							
Regulatory Asset	$ -	$ 14,544,577	$ 14,544,577	$ 14,544,577	$ 14,544,577	$ 14,544,577	$ 14,544,577
Accumulated Amortization		$ (2,908,915)	$ (5,817,831)	$ (8,726,746)	$ (11,635,662)	$ (14,544,577)	$ (14,544,577)
ADIT	$ -	$ (4,604,231)	$ (3,453,174)	$ (2,302,116)	$ (1,151,058)	$ -	$ -
Unamortized ITC	$ -	$ -	$ -	$ -	$ -	$ -	
Rate Base, end of year	$ -	$ 7,031,430	$ 5,273,573	$ 3,515,715	$ 1,757,858	$ -	$ -
Revenue Requirement							
Carrying Costs	$ -	$ 931,769	$ 675,558	$ 482,542	$ 289,525	$ 96,508	$ -
Regulatory Asset Amortization	$ -	$ 2,908,915	$ 2,908,915	$ 2,908,915	$ 2,908,915	$ 2,908,915	$ -
Gross Revenue Requirement		$ 3,840,685	$ 3,584,474	$ 3,391,457	$ 3,198,440	$ 3,005,424	$ -

EERP POA – Exhibit 1 – Example Revenue Requirements

2014 Revenue Requirement

Year 2014	Capitalization of EE Investments	
	[redacted]	Original Cost
	5	Asset Life
	39.6%	Income Tax Rate
	7.74%	Nominal Return
	10.98%	Pre-tax Return
	6.64%	After-tax Return
		Capital Structure:
	54.00%	Debt
	46.00%	Equity
		Short-Term Debt
		Cost of Capital:
	5.18%	Debt
	10.75%	Equity
		Short-Term Debt

		2014	2015	2016	2017	2018	2019
	0	1	2	3	4	5	6
Regulatory Asset Amortization		$ 4,947,838	$ 4,947,838	$ 4,947,838	$ 4,947,838	$ 4,947,838	$ -
Tax depreciation	$ -	$ 24,739,192	$ -	$ -	$ -	$ -	$ -
Net book basis (end of year)	$ -	$ 19,791,354	$ 14,843,515	$ 9,895,677	$ 4,947,838	$ -	$ -
Tax basis (end of year)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ADIT (end of year) ((book basis minus tax basis) times t	$ -	$ 7,831,439	$ 5,873,579	$ 3,915,719	$ 1,957,860	$ -	$ -
Long-term debt balance (end of year)	$ -	$ 6,458,354	$ 4,843,766	$ 3,229,177	$ 1,614,589	$ -	$ -
LT Debt Interest		$ 403,743	$ 292,725	$ 209,089	$ 125,454	$ 41,818	$ -
Rate Base, end of year							
Regulatory Asset	$ -	$ 24,739,192	$ 24,739,192	$ 24,739,192	$ 24,739,192	$ 24,739,192	$ 24,739,192
Accumulated Amortization		$ (4,947,838)	$ (9,895,677)	$ (14,843,515)	$ (19,791,354)	$ (24,739,192)	$ (24,739,192)
ADIT	$ -	$ (7,831,439)	$ (5,873,579)	$ (3,915,719)	$ (1,957,860)	$ -	$ -
Unamortized ITC	$ -	$ -	$ -	$ -	$ -	$ -	
Rate Base, end of year	$ -	$ 11,959,915	$ 8,969,936	$ 5,979,957	$ 2,989,979	$ -	$ -
Revenue Requirement							
Carrying Costs	$ -	$ 1,584,867	$ 1,149,072	$ 820,766	$ 492,459	$ 164,153	$ -
Regulatory Asset Amortization	$ -	$ 4,947,838	$ 4,947,838	$ 4,947,838	$ 4,947,838	$ 4,947,838	$ -
Gross Revenue Requirement		$ 6,532,705	$ 6,096,910	$ 5,768,604	$ 5,440,298	$ 5,111,992	$ -

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EERP POA –Exhibit 1 – Example Revenue Requirements

2016 Revenue Requirement

Year	Capitalization of EE Investments	
2016	[redacted]	Original Cost
	5	Asset Life
	39.6%	Income Tax Rate
	7.74%	Nominal Return
	10.98%	Pre-tax Return
	6.64%	After-tax Return
		Capital Structure:
	54.00%	Debt
	46.00%	Equity
		Short-Term Debt
		Cost of Capital:
	5.18%	Debt
	10.75%	Equity
		Short-Term Debt

		2016	2017	2018	2019	2020	2021
	0	1	2	3	4	5	6
Regulatory Asset Amortization		$ 5,571,251	$ 5,571,251	$ 5,571,251	$ 5,571,251	$ 5,571,251	$ -
Tax depreciation	$ -	$ 27,856,255	$ -	$ -	$ -	$ -	$ -
Net book basis (end of year)	$ -	$ 22,285,004	$ 16,713,753	$ 11,142,502	$ 5,571,251	$ -	$ -
Tax basis (end of year)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ADIT (end of year) ((book basis minus tax basis) times t	$ -	$ 8,818,176	$ 6,613,632	$ 4,409,088	$ 2,204,544	$ -	$ -
Long-term debt balance (end of year)	$ -	$ 7,272,087	$ 5,454,065	$ 3,636,044	$ 1,818,022	$ -	$ -
LT Debt Interest		$ 454,614	$ 329,607	$ 235,434	$ 141,260	$ 47,087	$ -
Rate Base, end of year							
Regulatory Asset	$ -	$ 27,856,255	$ 27,856,255	$ 27,856,255	$ 27,856,255	$ 27,856,255	$ 27,856,255
Accumulated Amortization		$ (5,571,251)	$ (11,142,502)	$ (16,713,753)	$ (22,285,004)	$ (27,856,255)	$ (27,856,255)
ADIT	$ -	$ (8,818,176)	$ (6,613,632)	$ (4,409,088)	$ (2,204,544)	$ -	$ -
Unamortized ITC	$ -	$ -	$ -	$ -	$ -	-	
Rate Base, end of year	$ -	$ 13,466,828	$ 10,100,121	$ 6,733,414	$ 3,366,707	$ -	$ -
Revenue Requirement							
Carrying Costs		$ 1,764,555	$ 1,293,852	$ 924,180	$ 554,508	$ 184,836	$ -
Regulatory Asset Amortization		$ 5,571,251	$ 5,571,251	$ 5,571,251	$ 5,571,251	$ 5,571,251	$ -
O & M		$ -	$ -	$ -	$ -	$ -	$ -
Gross Revenue Requirement		$ 7,355,806	$ 6,865,103	$ 6,495,431	$ 6,125,759	$ 5,756,087	$ -

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Self-Direction Option

Self-Direction is an option that will be made available to large qualifying industrial customers. Self-Direction allows participating customers to reserve their DSM/EE contributions, less administrative and other program costs, for their exclusive use to help fund qualifying DSM/EE projects at their facilities. Self-Direction will be offered to the largest customers since they have the ability and resources (technical knowledge, expertise, and funding) to implement effective DSM/EE and they may desire to have the flexibility to use their DSM/EE contributions to fund their own energy efficiency projects. The following parameters define the Self Direction option:

1. To be eligible for Self-Direction, a customer must use a minimum of 35 million kWh per calendar year, based on an aggregation of all of the customer's TEP accounts.
2. Qualifying Self-Direction customers who choose to self-direct their DSM/EE funds must elect Self-Direction by notifying the Company in each year that they wish to Self-Direct. Customers who elect to Self-Direct must continue to contribute their share of DSM/EE funds through the DSMS.
3. After a customer notifies the Company of their intent to Self-Direct, 90% of the customer's DSMS contribution will be reserved for tracking purposes for the customer's future energy efficiency project. The remaining 10% will be retained to cover the Self-Direction program administration, management, and MER costs.
4. Self-Direction funds will be reserved for tracking purposes for the calendar year the Self-Direction election is received by the Company. Such election must be received on or before December 1st. There will be no retroactive Self-Direction funds set aside from prior budget years, since the Company's books were closed prior to the customer's election.
5. Self-Direction funds will be paid to the qualifying customer once a year in December beginning in the year that the EE project is completed and verified. If project costs exceed the credited amount in one year, then funding will continue to be paid in December of each year until the project is 100% funded or in the fourth year of funding, or until the Commission terminates this program, whichever comes sooner.
6. If the EE project is not completed within two (2) years of the Self-Direction election date, then the Self-Direction funds from the first calendar year from the Self-Direction election will not be available to the customer and will revert to the DSMS general account.
7. Qualifying customers will be required to commit all of their facilities to the Self-Direction option for the duration of the specific Self-Direction project's funding period. Customers would not be able to designate some of their accounts for Self-Direction, while allowing some of their other accounts to remain eligible for other TEP commercial EE programs. Customers choosing to Self-Direct will not be permitted to participate in any other TEP commercial EE program offerings for any of their accounts.
8. Aggregation would be allowed only within a given customer set of accounts, not across groups of customers. This means that groups of customers would not be able to form buying associations for the purpose of meeting the Self-Direction size criteria.

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 702
Superseding:

Rider R-2
Demand Side Management Surcharge (DSMS)

APPLICABILITY
The Demand Side Management Surcharge (DSMS) applies to all Customers in the entire territory served by the Company as mandated by the Arizona Corporation Commission (ACC), unless otherwise specified.

RATE
The DSMS shall be applied to all monthly bills. The Rate is shown in the TEP Statement of Charges.

REQUIREMENTS
The 2013 TEP DSMS is effective XXXX, XX, 2013, and will remain in effect until further order by the ACC.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the ACC see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

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 ACC shall apply where not inconsistent with this Rider

ATTACHMENT "E"

Attachment E

INCREMENTAL FIXED OPTION LFCR CHARGES FOR RESIDENTIAL CUSTOMERS

Standard Service or Time of Use Service

Addition to Customer Charge with usage less than 2,000 kWh	$2.50 per month
Addition to Customer Charge with usage of 2,000 kWh or more	$6.50 per month

ATTACHMENT "F"

TUCSON ELECTRIC POWER COMPANY
LOST FIXED COST RECOVERY MECHANISM ("LFCR")
PLAN OF ADMINISTRATION

Table of Contents

1. General Description

This document describes the plan of administration for the LFCR mechanism approved for Tucson Electric Power ("TEP" or "Company") by the Arizona Corporation Commission ("ACC") in Decision No. xxxxx (date). The LFCR mechanism provides for the recovery of lost fixed costs, as measured by a reduction in non-fuel revenue, associated with the amount of energy efficiency ("EE") savings and distributed generation ("DG") that is authorized by the Commission and determined to have occurred. Costs to be recovered through the LFCR include the portion of transmission and distribution costs included in base rates exclusive of the Customer Charge and 50% of the demand rates in effect.

2. Definitions

Applicable Company Revenues – The amount of revenue generated by sales to retail customers, for all applicable rate schedules, less the amount attributable to sales to those residential customers who chose the Fixed Cost Option.

Current Period – The most recent adjustment year.

Demand Stability Factor – Fifty percent of Demand-based revenue (excluding any purchased power and fuel costs) produced by base rates.

Distribution and Transmission Revenue – The amount of revenue determined at the conclusion of a rate case by multiplying each participating rate class' adjusted test year billing determinants (kWh) by their approved distribution and transmission related charges. This will be determined by reducing each class' total retail revenue by the customer charge revenue, generation related revenue, purchased power and fuel costs and the Demand Stability Factor.

DG Savings – The amount of kWh sales or kW of capacity reduced by DG. TEP will use meter data for determining the kWh or kW lost through the implementation of DG systems unless a rare circumstance occurs where the meter data is not available at which time the lost sales will be quantified using statistical verification or output profile or other Commission authorized methods. Each year, TEP will use actual data through December to calculate the savings. The calculation of DG savings will consist of the following by class:

1. Cumulative Verified: The total kWh or kW reduction as metered each year less the total kWh or kW reduction metered in TEP's most recent general rate case test year (2011). The initial Cumulative Verified term of the LFCR will begin on January 1, 2013.

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2. Current Period: The annual kWh or kW produced by the cumulative total of DG installations since the end of the test year used in TEP's most recent general rate case.
3. The only DG Savings that will be excluded from the calculated Lost Fixed Cost Revenue calculation are those kWh or kW that were lost as the result of actions by customers in excluded rate classes.
4. The annual kW capacity of the cumulative total of DG installations since the end of the test year used in TEP's most recent general rate case. For solar systems only, the actual kW capacity used to calculate lost revenues for applicable demand metered customers will be the actual solar generation measured by the Solar production meter coincident with the customer's maximum fifteen minute demand for the billing period.

Fixed Cost Option – The rate schedule choice for residential customers who prefer contributing to the recovery of Lost Fixed Cost Revenue in the form of an optional fixed rate added as an incremental charge to the Customer Charge in the applicable residential tariff rate. The total dollars paid as an incremental amount added to the otherwise effective Customer Charge will be accumulated over the Current Period and used to reduce the total Lost Fixed Cost Revenue recovered as part of the LFCR adjustment. The variable LFCR adjustment shall not be applied to residential customers who choose the Fixed Cost option. This rate will be reflected as an incremental addition to the customer charge on the otherwise effective tariff and made available to customers at the time of the first LFCR adjustment. Customers choosing this fixed option within the first twelve months subsequent to the initial effective date of the LFCR will be allowed to change back to the volumetric option one time without any penalties. After the initial twelve month period, customers will be required to stay on which ever option they choose for twelve full months before a change can be made.

EE Programs – Any program approved in TEP's Energy Efficiency/Demand Side Management ("EE/DSM") implementation plan.

EE Savings – The amount of sales, expressed in kWh or kW, reduced by Energy Efficiency activities as demonstrated by the Measurement, Evaluation, and Research ("MER") conducted for TEP's EE Programs. The Company's EE activities are being reviewed as part of the MER evaluation and will determine the total kWh or kW lost as a result of those activities. As part of this filing the Commission Staff will have the option of reviewing any portion of the filing they deem necessary to verify the filings accuracy. EE Savings shall be quantified based on the cumulative lost kWh or kW occurring starting January 1, 2013 and shall be reset as of the end of the test year in each subsequent rate case. The calculation of EE Savings will consist of the following by class:

1. Cumulative Verified: The cumulative total kWh or kW reduction as determined by the MER recognizing that the cumulative total is reset (to zero) at the end of each of TEP's most recent general rate case. The first such reset will be January 1, 2012, (the end of the Test Year in Decision xxxxx, dated xx,). The initial Cumulative Verified term of the LFCR will begin on January 1, 2013.
2. Current Period: The annual EE related sales reductions (kWh or kW). Each year, TEP will use actual MER data through December to calculate savings.

3. Excluded kWh reduction: The reduction of recoverable EE Savings calculated by subtracting the amount of EE Savings actually achieved by customers on Excluded Rate Schedules if included in the total reported in the annual EE/DSM filing.

Effective Period – The twelve month period beginning with July 1 of each year, when the LFCR will be charged.

Excluded Rate Schedules – The LFCR mechanism shall not apply to Traffic Signal and Street Lighting Service (PS-41), ~~the l~~Lighting Service (GS-50), ~~w~~Water ~~p~~Pumping Service (GS-43), or the ~~l~~Large ~~l~~Light and ~~p~~Power Service (LLP-14 and LLP-90) rate schedules.

LFCR Adjustment – An amount calculated by dividing Lost Fixed Cost Revenue (As reduced by the total incremental fixed cost option dollars paid by the residential customers who have chosen the Fixed Cost Option and will be based on the incremental increase in the customer charge they have paid over the twelve-months during the Current Period.) by the Current period's retail revenue (less the estimated sales to the residential customers who chose the Fixed Cost Option) during the Effective Period for the participating rate classes. This percentage adjustment rate will be applied to all customer bills, excluding those on Excluded Rate Schedules.

Lost Fixed Cost Rate - A rate determined at the conclusion of a rate case by taking the sum of allowed Distribution and Transmission Revenue (which excludes the customer charge, the generation component and purchased power and fuel) for each rate class and dividing each by their respective class adjusted test year kWh and/or kW billing determinants.

Lost Fixed Cost Revenue - The amount of fixed costs not recovered by the utility because of EE and DG Savings during the measurement period. This amount is calculated by multiplying the Lost Fixed Cost Rate by Recoverable kWh Savings, by rate class.

Recoverable kWh Savings - The sum of EE and DG Savings by applicable rate class.

3. *LFCR Annual Incremental Cap*

The LFCR Adjustment will be subject to an annual 1% year over year cap based on Applicable Company Revenues. If the annual incremental LFCR Adjustment results in a surcharge in excess of 1% of Applicable Company Revenues, any amount in excess of the 1% cap will be deferred for collection until the next year. Any deferred amounts will be collected in a subsequent year or rolled into the next rate case, whichever occurs first. Where the 1% cap limits the recovery of deferrals in any program year, and thus moves their recovery to the following year, a first-in, first-out ("FIFO") approach will be applied. In connection therewith, the new surcharge billed in the following year will first recover any such carried-over deferrals, and then recover new deferrals arising in that following year. The one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15 or its successor publication will be applied annually to any deferred balance. The interest rate shall be adjusted annually and shall be that annual rate applicable to the first business day of the calendar year.

The initial LFCR filing will reconcile unrecovered lost revenues from January 1, 2013 through December 31, 2013.

4. *Filing and Procedural Deadlines*

TEP will file the calculated Annual LFCR Adjustment, including all Compliance Reports, with the Commission for the previous year by May 15th of each year. Staff will use its best efforts to process the matter based on the results of the Company's annual EE/DSM and Renewable Energy Standard Tariff ("REST") filings such that a new LFCR adjustment may go into effect by July 1st of each year. However, the new LFCR Adjustment will not go into effect until approved by the Commission.

5. ***Compliance Reports***

TEP will provide comprehensive compliance reports to Staff and the Residential Utility Consumer Office by May 15th of each year. The information contained in the Compliance Reports will consist of the following schedules:

- Schedule 1 : LFCR Annual Percentage Adjustment Rate
- Schedule 2: LFCR Annual Incremental Cap Calculation
- Schedule 3: LFCR Calculation
- Schedule 4: LFCR Test Year Rate Calculation
- Schedule 5: Distribution and Transmission Revenue Calculation

SCHEDULES

Schedule 1

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 1: LFCR Annual Adjustment Rate (Percentage)
($000)

Line No.	(A) Annual Per kWh Adjustment	(B) Reference		(C) Total
1.	Total Lost Fixed Cost Revenue for Current Period	Schedule 2, Line 13	$	-
2.	Forecast of Applicable Company's Revenues	Schedule 2, Line 1		-
3.	Percentage Adjustment Applied to Customer's Bills	(Line 1 / Line 2)		0.0000%

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Schedule 2

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 2: LFCR Annual Incremental Cap Calculation
($000)

Line No.	(A) LFCR Annual Incremental Cap Calculation	(B) Reference		(C) Totals
1	Applicable Company Revenues		$	
2	Allowed Cap %			1.00%
3	Maximum Allowed Incremental Recovery	(Line 1 * Line 2)	$	-
4	Total Lost Fixed Cost Revenue	Schedule 3, Line 55, Column C	$	-
5	Total Deferred Balance from Previous Period	Previous Filing, Schedule 2, Line 11, Column C		-
6	Annual Interest Rate			0.00%
7	Interest Accrued on Deferred Balance	(Line 5 * Line 6)		-
8	Total Lost Fixed Cost Revenue Current Period	(Line 4 + Line 5 + Line 7)	$	-
9	Lost Fixed Cost Revenue from Prior Period	Previous Filing, Schedule 2, Line 13, Column C	$	-
10	Total Incremental Lost Fixed Cost Revenue for Current Year	(Line 8 - Line 9)	$	-
11	Amount in Excess of Cap to Defer	(Line 10 - Line 3)	$	-
12	Incremental Period Adjustment	[(Line 10 - Line 11)/ Line 1]		-
13	Total Lost Fixed Cost Revenue for Current Period	(Line 8 - Line 11)	$	-

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation
($000)

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units
	Residential				
	Energy Efficiency Savings				
1	Current Period				kWh
2	% of Residential Customers choosing fixed-option			0.0%	
3	Excluded kWh reduction	(Line 1 * Line 2)		-	kWh
4	Net - Current Period	(Line 1 - Line 3)		-	kWh
5	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 6, Column C		-	kWh
6	Cumulative Recoverable kWh savings	(Previous Filing, Schedule 3, Line 6, Column C + Line 4)		-	kWh
7	Total Recoverable EE Savings	Line 6		-	kWh
8	Residential - Lost Fixed Cost Rate	Schedule 4, Line 3, Column C	$	0.0308	$/kWh
9	Residential - Lost Fixed Cost Revenue Relating to EE	(Line 7 * Line 8)	$	-	
	Distributed Generation				
10	Current Period				kWh
11	% of Residential Customers choosing fixed-option			0.0%	
12	Excluded kWh reduction	(Line 10 * Line 11)		-	kWh
13	Net - Current Period	(Line 10 - Line 12)		-	kWh
14	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 15, Column C		-	kWh
15	Cumulative Recoverable kWh savings	(Previous Filing, Schedule 3, Line 15, Column C + Line 13)		-	kWh
16	Total Recoverable DG Savings	Line 15		-	kWh
17	Residential - Lost Fixed Cost Rate	Schedule 4, Line 3, Column C	$	0.0308	$/kWh
18	Residential - Lost Fixed Cost Revenue Relating to EE	(Line 16 * Line 17)	$	-	
	Small General Service				
	Energy Efficiency Savings				
19	Current Period			-	kWh
20	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 21, Column C		-	kWh
21	Cumulative Recoverable kWh savings	(Previous Filing, Schedule 3, Line 21, Column C + Line 19)		-	kWh
22	Total Recoverable EE Savings	Line 21		-	kWh
23	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 6, Column C	$	0.0314	$/kWh
24	Small General Service - Lost Fixed Cost Revenue Relating to EE	(Line 22 * Line 23)	$	-	
	Distributed Generation				
25	Current Period			-	kWh
26	Prior Period kWh DG losses	Previous Filing, Schedule 3, Line 27, Column C		-	kWh
27	Cumulative Recoverable kWh savings	(Previous Filing, Schedule 3, Line 27, Column C + Line 25)		-	kWh
28	Total Recoverable DG Savings	Line 27		-	kWh
29	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 6, Column C	$	0.0314	$/kWh
30	Small General Service - Lost Fixed Cost Revenue Relating to DG	(Line 28 * Line 29)	$	-	

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation
($000)

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units
	Large General Service - Delivery Revenue - Demand				
	Energy Efficiency Savings				
31	Current Period			-	kW
32	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 33, Column C		-	kW
33	Cumulative Recoverable kW savings	(Previous Filing, Schedule 3, Line 33, Column C + Line 31)		-	kW
34	Total Recoverable EE Savings	Line 33		-	kW
35	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 9, Column C	$	2.3901	$/kW
36	Large General Service - Lost Fixed Cost Revenue Relating to EE	(Line 34 * Line 35)	$	-	
	Distributed Generation				
37	Current Period			-	kW
38	Prior Period kW DG losses	Previous Filing, Schedule 3, Line 39, Column C		-	kW
39	Cumulative Recoverable kW savings	(Previous Filing, Schedule 3, Line 39, Column C + Line 37)		-	kW
40	Total Recoverable DG Savings	Line 39		-	kW
41	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 9, Column C	$	2.3901	$/kW
42	Large General Service - Lost Fixed Cost Revenue Relating to DG	(Line 40 * Line 41)	$	-	
	Large General Service - Delivery Revenue				
	Energy Efficiency Savings				
43	Current Period			-	kWh
44	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 45, Column C		-	kWh
45	Cumulative Recoverable kWh savings	(Previous Filing, Schedule 3, Line 45, Column C + Line 43)		-	kWh
46	Total Recoverable EE Savings	Line 45		-	kWh
47	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 12, Column C	$	0.0042	$/kWh
48	Large General Service - Lost Fixed Cost Revenue Relating to EE	(Line 46 * Line 47)	$	-	
	Distributed Generation				
49	Current Period			-	kWh
50	Prior Period kWh DG losses	Previous Filing, Schedule 3, Line 51, Column C		-	kWh
51	Cumulative Recoverable kWh savings	(Previous Filing, Schedule 3, Line 51, Column C + Line 49)		-	kWh
52	Total Recoverable DG Savings	Line 51		-	kWh
53	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 12, Column C	$	0.0042	$/kWh
54	Large General Service - Lost Fixed Cost Revenue Relating to DG	(Line 52 * Line 53)	$	-	
55	Total Lost Fixed Cost Revenue	Sum Line 9 + 18 + 24 + 30 + 36 + 42 + 48 + 54	$	-	

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 4: LFCR Test Year Rate Calculation
($000)

Line No.	(A) LFCR Fixed Cost Calculation	(B) Reference		(C) Total
	Residential Customers			
1	Delivery Revenue	Schedule 5, Line 5, Column F	$	111,739,643
2	kWh Billed	Forecasted		3,627,093,708
3	Lost Fixed Cost Rate	Line 1/Line 2	$	0.0308
	Small General Service			
4	Delivery Revenue	Schedule 5, Line 8, Column F	$	63,186,286
5	kWh Billed	Forecasted		2,012,114,954
6	Lost Fixed Cost Rate	Line 4/Line 5	$	0.0314
	Large General Service			
7	Delivery Revenue - Demand	Schedule 5, Line 13, Column F	$	8,172,790
8	kW Billed	Forecasted		3,419,489
9	Lost Fixed Cost Rate	Line 7/Line 8	$	2.3901
	Large General Service			
10	Delivery Revenue	Schedule 5, Line 16, Column F	$	5,319,772
11	kWh Billed	Forecasted		1,261,678,481
12	Lost Fixed Cost Rate	Line 10/Line 11	$	0.0042

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 5: Delivery Revenue Calculation
($000)

	(A)	(B)	(C)	(D)	(E)	(F) B x D x E
Line No.	Rate Schedule	Adjusted Test Year Billing Determinants	Units	Delivery Charge	Demand Stability Factor	Total Delivery Revenue
1	Residential Service (R-01)	3,368,532,306	kWh	$ 0.0314	100%	$ 105,811,858
2	Residential Service (R-80)	116,359,255	kWh	$ 0.0229	100%	$ 2,664,627
3	Residential Service (R-201AN)	131,427,481	kWh	$ 0.0230	100%	$ 3,016,454
4	Residential Service (R-201BN)	10,774,668	kWh	$ 0.0229	100%	$ 246,705
5	Subtotal - kWh	3,627,093,708	kWh	$		$ 111,739,643
6	Small General Service (GS-10)	1,888,524,435	kWh	$ 0.0314	100%	$ 59,326,481
7	Small General Service (SGS-76)	123,590,518	kWh	$ 0.0312	100%	$ 3,859,805
8	Subtotal - kWh	2,012,114,954	kWh			$ 63,186,286
9	Large General Service (LGS-13) - kW	2,719,841	kW	$ 5.13	50%	$ 6,976,392
10	Large General Service (LGS-85) - kW	699,648	kW	$ 3.42	50%	$ 1,196,398
11	Subtotal - kW - Demand	3,419,489	kW			$ 8,172,790
12	Large General Service (LGS-13)	1,045,063,814	kWh	$ 0.0049	100%	$ 5,071,019
13	Large General Service (LGS-85)	216,614,667	kWh	$ 0.0011	100%	$ 248,753
14	Subtotal - kWh - Delivery	1,261,678,481	kWh			$ 5,319,772

DECISION NO. 73912

Docket No. E-01933A-12-0291

ATTACHMENT
"G"

TUCSON ELECTRIC POWER COMPANY
ENVIRONMENTAL COMPLIANCE ADJUSTOR ("ECA")
PLAN OF ADMINISTRATION

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1. GENERAL DESCRIPTION

This document describes the plan for administering the ECA as approved by the Arizona Corporation Commission ("Commission" or "ACC") for Tucson Electric Power Company ("TEP") in Decision No. XXXXX [DATE]. The ECA provides for the recovery of and return on capital investments and associated costs related to environmental investments made by TEP and not already recovered in base rates approved in Decision No. XXXXX or recovered through another Commission-approved mechanism. The ECA will be calculated annually based on the ECA Qualified Investments closed to plant-in-service during the preceding calendar year.

2. DEFINITIONS

ECA Qualified Investments – Investments in Qualified Environmental Compliance Projects. Each ECA Qualified Investment shall: 1) be classified in one or more of the FERC Plant In-Service accounts listed in Section 3 of this document, or any other successor FERC account, upon going into service; and 2) be tracked by a specific project number.

Qualified Environmental Compliance Projects - Those projects designed to comply with established environmental standards required by federal, state, tribal, or local laws and regulations. In general, these environmental standards include, but are not limited to the following: sulfur dioxide, nitrogen oxide, carbon dioxide, ozone, particulate matter, volatile organic compounds, mercury and other toxics, coal ash and other combustion residuals and water intake.

Capital Carrying Costs – Costs recovered through the ECA charge include return on ECA Qualified Investments based on TEP's Weighted Average Cost of Capital ("WACC") approved by the Commission in Decision No. XXXXX; depreciation expense; income taxes; property taxes; deferred income taxes and tax credits where appropriate; and associated operations and management ("O&M") costs.

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6. ACCOUNTING

From the effective date of the ECA, all ECA Capital Carrying Costs, including operating and maintenance expenses, depreciation, taxes, and the debt component of the WACC will be recorded in Other Regulatory Assets in Account 182.3, as they are incurred. Each month as the ECA surcharge revenues are billed, corresponding amortizations will be made from Account 182.3 and recorded in the proper income statement expense accounts. ECA Qualified Investments will continue to be accounted for as Plant In-Service.

7. RECOVERY PERIOD

The initial ECA measurement period will become effective August 1, 2013. The ECA per kWh rate is designed to recover the annual ECA Capital Carrying Costs over a 12-month period. Should the ECA be modified or discontinued, any unrecovered balance in the ECA regulatory asset shall continue to be recovered through the ECA surcharge until all such costs have been collected.

8. FILING AND PROCEDURAL DEADLINES

TEP will file the calculated ECA rate including all supporting data with the Commission for the previous calendar year on or before March 1st. See Schedules 1 and 2, attached.

The Commission Staff and interested parties shall have the opportunity to review the ECA filing and supporting data in the adjustor calculation. Unless the Commission has otherwise acted to suspend the filing or Staff has filed an objection by May 1st, the new ECA rate proposed by TEP will go into effect with the first billing cycle in May (without proration) and will remain effective for the following 12-month period.

Schedule 1: Qualified Investments for ECA
Electric Plant In Service for Calendar Year 20XX

Electric Plant in Service

Line No.	(A) Project Tracking Number	(B) Project Name	(C) Purpose	(D) In-Service Date	(E) Total Cost	(F) ACC Jurisdictional Total Cost
	Qualified Environmental Compliance Projects					
1.	XXXX	Project A	Project A Purpose Description	MM/YY	$ -	$ -
2.	XXXX	Project B	Project B Purpose Description	MM/YY	$ -	$ -
3.	XXXX	Project C	Project C Purpose Description	MM/YY	$ -	$ -
4.		Total			$ -	$ -

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Schedule 2: Capital Carrying Costs and Adjustor Calculation
Plant in Service for Calendar Year 20XX
Billing Period 1/1/20XX-12/31/XX

Line No.	ECA Rate Calculation		
	Qualified Net Plant		
1.	Qualified Environmental Compliance Projects (Schedule 1 - Total Line Colur	$	-
2.	Accumulated Depreciation	$	-
3.	Cumulative Deferred Tax/Tax Credits	$	-
4.	Qualified Net Plant (Line 1 - Line 2 - Line 3)	$	-
5.	Pre-Tax Weighted Average Cost of Capital		0.00%
	ECA Revenue Requirement		
6.	Composite Return on ECA Net Plant (Line 4 * Line 5)	$	-
7.	Annual Depreciation of Plant in Service	$	-
8.	Applicable Property Tax	$	-
9.	Associated O&M Expense	$	-
10.	Total ECA Capital Carrying Costs (Line 6 + Line 7 + Line 8 + Line 9)	$	-
11.	Total Company Retail Sales (kWh)		
12.	Calculated ECA Rate ($/kWh) (Line 10 / Line 11)		
13.	ECA Rate Cap ($/kWh)	$	0.00025
14.	ECA Rate ($/kWh) Lesser of Line 13 or Line 14	$	-

ATTACHMENT "H"

ATTACHMENT H

PROCUREMENT RECOMMENDATIONS

1. TEP should prepare a complete natural gas hedging plan consistent with the requirements outlined in the TEP Hedging Manual.
2. TEP should revise its hedging strategy for natural gas and power to reflect the fundamental changes in the energy markets.
3. TEP should reduce the unit cost of coal in determining cost of coal in inventory by non-recurring costs and ash handling costs.
4. TEP should add resources to the solid fuel group to develop additional support for current solid fuel activities.
5. TEP should develop a plan to minimize solid fuel cost consequences of any decisions to retire plants in response to regional haze requirements.

ATTACHMENT "I"

ATTACHMENT I - COMPARISON OF LOW INCOME BILL IMPACT WITH AUGUST 2013 PPFAC

Line No.	Class Description	Customer Counts	Average Annual Bill	Average Annual Bill Change (from Current)	Revised Percent Change to Total Bill	$ change in monthly bill	Lifeline bill below R-01 monthly bill
1	Residential R-01	330,848	$966.06	$34.92	3.8%	$2.91 (1)	
2	Residential Lifeline R-04-01	819	$647.15	$31.64	5.1%	$2.64	$26.58
3	Residential Lifeline R-05-01	1,722	$736.03	$36.01	5.1%	$3.00	$19.17
4	Residential Lifeline R-08-01	1,046	$577.75	$28.45	5.2%	$2.37	$32.36
5	Residential Lifeline R-06-01	13,376	$780.85	$31.77	4.2%	$2.65	$15.43
6	Residential Lifeline R-04-21F	4	$562.14	$36.91	7.0%	$3.08	$33.66
7	Residential Lifeline R-05-21F	4	$639.29	$42.01	7.0%	$3.50	$27.23
8	Residential Lifeline R-08-21F	9	$501.49	$33.13	7.1%	$2.76	$38.71
9	Residential Lifeline R-06-21F	25	$663.52	$38.96	6.2%	$3.25	$25.21
10	Residential Lifeline R-04-70F	6	$600.59	$34.73	6.1%	$2.89	$30.46
11	Residential Lifeline R-05-70F	16	$682.93	$39.50	6.1%	$3.29	$23.59
12	Residential Lifeline R-08-70F	24	$535.20	$31.04	6.2%	$2.59	$35.91
13	Residential Lifeline R-06-70F	109	$715.39	$35.76	5.3%	$2.98	$20.89
14	Residential Lifeline 05- 201AF	3	$688.32	$37.13	5.7%	$3.09	$23.15
15	Residential Lifeline 08- 201AF	12	$538.99	$29.36	5.8%	$2.45	$35.59
16	Residential Lifeline 06- 201AF	336	$721.21	$33.16	4.8%	$2.76	$20.40
17	Residential Lifeline 06- 201BF	12	$656.83	$31.70	5.1%	$2.64	$25.77

Note (1) This reflects the inclusion of the PPFAC rate as proposed in the Settlement, which includes $3 million of sulfur credits, deferral of $9.7 million of San Juan "thermal event" costs. Impacts do not include the anticipated changes in DSM or REST rates.

ATTACHMENT
"J"

TUCSON ELECTRIC POWER COMPANY
SUMMARY OF CURRENT, PROPOSED AND SETTLEMENT RATE DESIGN

Rate Schedule	Current Design	Settlement
Lifeline	• Includes 19 rate schedules with different designs • 12 different discounts – one flat and 11 percentage discounts • Excluded from PPFAC charges • Excluded from DSM charges • TOU schedules includes shoulder peak period in delivery • Fuel in base rates with shoulder peak period in TOU schedules	• Include PPFAC charges • Include DSM charges • Increased fixed rate discount from $8 to $9 • Remainder of rates adjusted upward to reflect the same overall dollar change as the R-01 class • No other changes in rate design
Residential **R-01**	• Three block structure • 6 summer months/6 winter months • Fuel in base rates	• Four block structure • Consolidated R-02 into R-01 • Increase customer and energy charges • 5 summer months/7 winter months • *Added AMI opt-out charge* • LFCR fixed charge option added • Base Power as in current structure
Residential **R-201**	• Two different rate structures with and without blocks • Rate structure includes three seasons • 6 summer months/6 winter months • Discounted from R-01 • Fuel in base rates	• Consolidated two rate schedules into one with four blocks • Changed to only a winter and summer season • 5 summer months/7 winter months • Includes 10% discount on non-fuel components to R-01 • Increase customer and energy charges • Base Power as in current structure

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TUCSON ELECTRIC POWER COMPANY
SUMMARY OF CURRENT, PROPOSED AND SETTLEMENT RATE DESIGN

Rate Schedule	Current Design	Settlement
Residential R-80 TOU	• Includes 5 rate structure with and without blocks • Includes three different on peak periods • Includes shoulder peak period in delivery • 6 summer months/6 winter months • Fuel in base rates with shoulder peak period	• Consolidated 5 TOU rate schedules into one without blocks • Consolidated on peak periods into a single period for the summer from 2:00 pm to 8:00 pm and two winter periods from 6:00 am to 10:00 am and 5:00 pm to 9:00 pm • Changed to only a winter and summer season • Removed shoulder peak period in delivery • Increase customer and energy charges • 5 summer months/7 winter months • Base Power as in current structure without shoulder peak period
Residential R-201 TOU	• Four different rate structures with and without blocks • Rate structure includes three seasons • Includes shoulder peak period in delivery • 6 summer months/6 winter months • Discounted from R-01 • Fuel in base rates with shoulder peak period	• Consolidated four rate schedules into one without blocks • Consolidated on peak periods into a single period for the summer from 2:00 pm to 8:00 pm and two winter periods from 6:00 am to 10:00 am and 5:00 pm to 9:00 pm • Changed to only a winter and summer season • Removed shoulder peak period in delivery • Increase customer and energy charges • 5 summer months/7 winter months • Includes 15% discount on non-fuel components toR-80 • Base Power as in current structure without shoulder peak period

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TUCSON ELECTRIC POWER COMPANY
SUMMARY OF CURRENT, PROPOSED AND SETTLEMENT RATE DESIGN

Rate Schedule	Current Design	Settlement
Small General Service GS-10	• One schedule with two blocks • 6 summer months/6 winter months • Fuel in base rates	• One schedule with two blocks • Increase customer and energy charges • 5 summer months/7 winter months • Municipal Rate 40 included in small general service with a 16.5% discount • Base Power as in current structure
Small General Service GS-76 TOU	• Two schedules with and without blocks • 6 summer months/6 winter months • Includes shoulder peak period in delivery • Fuel in base rates with shoulder peak period	• Consolidated on peak periods into a single period for the summer from 2:00 pm to 8:00 pm and two winter periods from 6:00 am to 10:00 am and 5:00 pm to 9:00 pm • Remove shoulder peak period • Increase customer and energy charges • 5 summer months/7 winter months • Base Power as in current structure without shoulder peak
Large General Service I-13	• Demand ratchet at 50% • 6 summer months/6 winter months • Fuel in base rates	• Increase customer charge • Standard demand and energy increases • Increased demand ratchet from 50% to 75% • 5 summer months/7 winter months • Base Power as in current structure
Large General Service I-85 TOU	• Three rate schedules with two different demand structures • Two different sets of on-peak periods • Includes shoulder peak period in delivery • 6 summer months/6 winter months • Demand ratchet at 50% • Fuel in base rates include shoulder peak period	• Consolidated three rate schedules into one • Consolidated on peak periods into a single period for the summer from 2:00 pm to 8:00 pm and two winter periods from 6:00 am to 10:00 am and 5:00 pm to 9:00 pm • Removed shoulder peak period • 5 summer months/7 winter months • Increase customer charge • Standard demand and energy increases • Increased demand ratchet from 50% to 75%

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TUCSON ELECTRIC POWER COMPANY
SUMMARY OF CURRENT, PROPOSED AND SETTLEMENT RATE DESIGN

Rate Schedule	Current Design	Settlement
		(ratchet will be new for 85N) • Base Power as in current structure without shoulder peak period
Large Light & Power I-14	• Demand ratchet at 66.7% • 6 summer months/6 winter months • Fuel in base rates • Power factor 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	• Increase customer charge • Standard demand and energy increases • Increased demand ratchet from 66.7% to 75% • 5 summer months/7 winter months • Base Power as in current structure • Power factor charges applied to all power factors under 100%
LL&P I-90 TOU	• Three rate schedules • Demand is On-peak & Excess • Two sets of on-peak periods • Includes shoulder peak periods in delivery • Demand ratchet at 50% • 6 summer months/6 winter months • Fuel in base rates with shoulder peak period • Power factor 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	• Consolidated three rate schedules into one • Consolidated on peak periods into a single period for the summer from 2:00 pm to 8:00 pm and two winter periods from 6:00 am to 10:00 am and 5:00 pm to 9:00 pm • Removed shoulder peak period • Increase customer charge • Standard demand and energy increases • Increased demand ratchet from 50% to 75% • 5 summer months/7 winter months • Base Power as in current structure without shoulder peak period • Power factor charges applied to all power factors under 100%

PROOF
OF
REVENUE

TUCSON ELECTRIC POWER COMPANY
SUMMARY PROPOSED REVENUES
TEST PERIOD ENDING DECEMBER 31, 2011

Line No.	Rate Class	Adjusted Customers	Adjusted Sales (kWh)	Margin Revenue	Base Power&PPFAC	Test Year Adjusted Revenue	Proposed Revenues Margin Revenue	Proposed Revenues Base Power	Proposed Revenues Total Revenue
1	Proposed Increased								
2									
3									
4	Residential Service	360,521	3,699,107,059	$241,095,410	$111,635,462	$352,730,872	$276,525,140	$123,201,293	$399,726,432
5	Residential Time Of Use	8,873	129,923,963	7,043,984	3,797,665	10,841,649	7,897,878	4,200,221	12,098,099
6	Small General Service	35,978	1,947,489,380	156,798,459	55,398,880	212,197,338	172,523,430	64,822,405	237,345,835
7	Small General Service Time of Use	924	123,590,519	8,103,358	3,384,976	11,488,333	10,026,004	3,922,266	13,948,270
8	Irrigation & Water Pumping	484	107,584,687	4,446,839	2,908,651	7,355,490	5,001,226	3,390,580	8,391,806
9	Large General Service	536	1,046,539,305	55,085,198	30,598,384	85,683,582	63,396,775	34,774,183	98,170,957
10	Large General Service Time of Use	87	216,614,667	8,424,561	6,579,663	15,004,224	9,974,701	6,773,309	16,748,010
11	Large Light & Power Service	4	351,454,280	12,469,651	10,271,504	22,741,155	15,465,873	10,507,517	25,973,390
12	Large Light & Power Service Time of Use	9	542,786,937	17,883,872	13,900,001	31,783,872	19,487,175	15,800,087	35,287,262
13	Mining Service	2	1,083,071,404	30,374,675	29,264,219	59,638,894	37,382,924	31,630,841	69,013,765
14	Traffic Signals & Lighting Service	19,566	37,430,789	3,022,183	913,817	3,936,000	3,261,519	1,230,412	4,491,931
15	TOTAL	426,985	9,285,592,991	$544,748,189	$268,653,221	$813,401,411	$620,942,644	$300,253,113	$921,195,757
16									
17	Rate Schedule								
18	R-01 - Lifeline	19,858	190,498,193	$11,801,193	$5,712,319	$17,513,513	$12,887,266	$5,598,340	$18,485,606
20	R-01	327,921	3,364,805,199	223,461,936	102,007,849	325,469,785	256,693,383	112,600,057	369,293,439
21	R-02	1,985	3,727,106	185,953	109,756	295,709	215,028	122,270	337,297
22	R-201AF	4,943	69,035,331	3,588,889	2,061,241	5,650,130	4,608,883	2,295,181	6,904,064
19	R-201AF - Lifeline	352	4,797,453	235,965	143,480	379,445	256,971	144,258	401,229
23	R-201AN	5,462	62,392,149	3,306,229	1,927,235	5,233,464	4,287,838	2,078,430	6,366,268
24	TOTAL RESIDENTIAL SERVICE	360,521	3,695,255,432	$242,580,166	$111,961,880	$354,542,046	$278,949,369	$122,838,536	$401,787,904
25									
26	R-21F - Lifeline	51	601,680	$27,889	$17,837	$45,726	$31,576	$17,578	$49,154
27	R-70F - Lifeline	198	2,036,942	114,504	59,014	173,519	124,671	58,266	182,937
28	R-201BF - Lifeline	13	151,418	6,684	4,342	11,025	7,338	4,284	11,621
29	R-21F	2,411	40,511,249	1,929,952	1,222,077	3,152,029	2,464,973	1,311,430	3,776,403
30	R-70F	4,110	59,486,521	3,441,136	1,722,450	5,163,586	3,708,397	1,931,874	5,640,271
31	R-70N-B	202	2,721,591	179,745	80,748	260,493	171,705	88,446	260,151
32	R-70N-C	651	7,853,166	519,667	232,140	751,807	504,697	255,111	759,808
33	R-70N-D	452	5,786,727	382,164	171,439	553,603	368,190	188,058	556,248
34	R-201BF	494	7,561,541	333,854	214,871	548,725	403,137	242,450	645,587
35	R-201CF	205	2,211,821	103,121	66,786	169,907	125,889	70,604	196,493
36	R-201BN	58	847,816	39,443	25,350	64,793	45,614	27,222	72,835
37	R-201CN	27	153,489	7,999	4,773	12,772	10,553	4,899	15,452
38	RESIDENTIAL TOU SERVICE	8,873	129,923,963	$7,086,159	$3,821,825	$10,907,984	$7,966,739	$4,200,221	$12,166,960
39									
40	Total Lifeline Discount Non-TOU			-1,484,756	-689,175	-2,173,931	-2,424,229		-2,424,229
41	Total Lifeline Discount TOU			-42,175	-24,160	-66,335	-68,861		-68,861
42	R-01 Community Solar		3,851,627	0	362,757	362,757		362,757	362,757
43	TOTAL RESIDENTIAL SERVICE	369,394	3,829,031,022	$248,139,394	$115,433,127	$363,572,522	$284,423,018	$127,401,513	$411,824,531

Total Retail kWh Sales – Total retail kWh sales served under applicable ACC jurisdictional rate schedules as reported in TEP's FERC Form No. 1 for the prior calendar year.

3. ECA QUALIFIED INVESTMENTS - FERC ACCOUNTS

Each ECA Qualified investment may be classified in one or more of the FERC Plant In Service accounts listed below, any successor FERC account, or any other FERC Account approved by the Commission upon going into service. The Plant In-Service FERC Accounts shall include the following:

Steam Production:

- FERC Account 310 – Land and Land Rights
- FERC Account 311 – Structures and Improvements
- FERC Account 312 – Boiler Plant Equipment
- FERC Account 313 – Engines and Engine-Driven Generators
- FERC Account 314 – Turbogenerator Units
- FERC Account 315 – Accessory Electric Equipment
- FERC Account 316 – Miscellaneous Power Plant Equipment

Other Production:

- FERC Account 340 – Land and Land Rights
- FERC Account 341 – Structures and Improvements
- FERC Account 342 – Fuel Holders, Products and Accessories
- FERC Account 343 – Prime Movers
- FERC Account 344 – Generators
- FERC Account 345 – Accessory Electric Equipment
- FERC Account 346 – Miscellaneous Power Plant Equipment

Please note that this list may expand to include other accounts approved by the ACC in the future.

4. CALCULATION OF ECA CAPITAL CARRYING COSTS

The recoverable ECA Capital Carrying Costs used in calculating the ECA $ per kWh rate will include: 1) Return on ECA Qualified Investments based on TEP's WACC approved by the Commission in Decision No. XXXXX; 2) depreciation expense; 3) income taxes; 4) property taxes; 5) deferred income taxes and tax credits where appropriate; and 6) associated O&M costs. The annual amount of Capital Carrying Costs to be recovered is subject to a cap equal to 0.25 percent of the total retail revenue requirement approved by the Commission in Decision No. xxxxx. The ECA Qualified Projects and the ECA recoverable costs calculation will be submitted by the Company to the Commission in the form of Schedule 1 and Schedule 2, as attached to this document.

5. CALCULATION OF ECA $ PER KWH RATE

The ECA rate to be applied to customers' bills will be calculated by dividing the total ECA Capital Carrying Costs by Total Retail kWh Sales. The ECA will not exceed $0.00025 per kWh. The initial ECA rate will be set to zero.

TUCSON ELECTRIC POWER COMPANY
SUMMARY PROPOSED REVENUES
TEST PERIOD ENDING DECEMBER 31, 2011

Line No.	Rate Class	Adjusted Customers	Adjusted Sales (kWh)	Margin Revenue	Base Power&PPFAC	Test Year Adjusted Revenue	Proposed Revenues Margin Revenue	Proposed Revenues Base Power	Proposed Revenues Total Revenue
1	Proposed Increased								
2	Rate Class								
3									
44									
45	C-10	34,902	1,770,219,715	$146,658,776	$50,263,037	$196,921,813	$159,673,752	$58,913,527	$218,587,279
46	C-11	339	58,614,700	3,567,768	1,684,000	5,251,768	4,229,714	1,944,430	6,174,144
48	P-40	737	118,304,720	6,571,915	3,412,958	9,984,873	10,240,806	3,925,564	14,166,371
49	SMALL GENERAL SERVICE	35,978	1,947,139,135	$156,798,459	$55,359,996	212,158,454	$174,144,272	$64,783,521	$238,927,793
50									
51	C76F	828	109,764,966	$6,970,469	$2,995,352	$9,965,821	$8,900,021	$3,481,756	$12,381,777
52	C-76-N	96	13,825,553	1,132,888	389,624	1,522,512	1,125,983	440,510	1,566,493
53	TOTAL SGS TIME OF USE	924	123,590,519	$8,103,358	$3,384,976	$11,488,333	$10,026,004	$3,922,266	$13,948,270
54									
55	C-31	30	14,173,519	$360,113	$407,205	$767,318	$532,645	$430,614	$963,259
56	P-43	339	50,179,432	2,931,269	1,341,303	$4,272,572	2,958,010	1,669,303	4,627,312
57	P-45	115	43,231,736	1,155,457	1,160,143	2,315,600	1,510,571	1,290,664	2,801,235
58	WATER PUMPING SERVICE	484	107,584,687	$4,446,839	$2,908,651	$7,355,490	$5,001,226	$3,390,580	$8,391,806
59									
60	I-13	535	1,045,063,814	$54,952,648	$30,548,289	$85,500,936	$63,264,224	$34,724,088	$97,988,311
61	Contract PRS	1	1,475,491	132,551	50,095	182,646	132,551	50,095	182,646
62	LARGE GENERAL SERVICE	536	1,046,539,305	$55,085,198	$30,598,384	$85,683,582	$63,396,775	$34,774,183	$98,170,957
63									
64	I-85AF	17	31,671,453	$1,644,562	$864,899	$2,509,460	$1,153,849	$1,043,983	$2,197,832
65	I-85F	7	14,642,750	802,338	403,378	1,205,716	609,482	449,816	1,059,298
66	I-85N	63	170,300,463	5,977,661	5,311,387	11,289,048	8,211,370	5,279,510	13,490,880
67	LARGE GENERAL SERVICE TOU	87	216,614,667	$8,424,561	$6,579,663	$15,004,224	$9,974,701	$6,773,309	$16,748,010
68									
47	P-40 Discount						-1,620,842		-1,620,842
69	C-10 - Community Solar		350,244		38,884	38,884		38,884	38,884
70	TOTAL GENERAL SERVICE	38,010	3,441,818,558	$232,858,415	$98,870,553	$331,728,968	$260,922,135	$113,682,744	$374,604,879
71									
72	LL&POWER SERVICE I-14	4	351,454,280	$12,469,651	$10,271,504	$22,741,155	$15,465,873	$10,507,517	$25,973,390
73									
74	I-90F - Contract	1	29,899,899	$973,212	$706,823	$1,680,035	$873,457	$806,578	$1,680,035
75	I-90F	3	170,484,054	5,971,902	3,996,602	$9,968,504	5,714,483	4,980,736	10,695,219
76	I-90AF	1	29,796,851	1,236,204	698,332	$1,934,536	1,012,873	873,371	1,886,244
77	I-90N	4	312,606,133	9,702,553	8,498,244	$18,200,797	11,886,363	9,139,401	21,025,764
78	TOTAL LL&POWER TOU SERVICE	9	542,786,937	$17,883,872	$13,900,001	$31,783,872	$19,487,175	$15,800,087	$35,287,262
79									
80	MINING SERVICE	2	1,083,071,404	30,374,675	$29,264,219	$59,638,894	37,382,924	$31,630,841	69,013,765
81	TOTAL LL&P & MINING SERVICE	15	1,977,312,622	$60,728,198	$53,435,723	$114,163,922	$72,335,972	$57,938,445	$130,274,417
82									
83	P-41	1,251	29,734,586	$1,355,302	$767,658	$2,122,960	$1,415,366	$977,598	$2,392,965
84	Lighting	18,316	7,696,203	1,666,880	146,159	$1,813,039	1,846,152	252,814	2,098,966
85	LIGHTING SERVICE	19,566	37,430,789	$3,022,183	$913,817	$3,936,000	$3,261,519	$1,230,412	$4,491,931
86									
87	TOTAL RETAIL SERVCIE	426,985	9,285,592,991	$544,748,189	$268,653,221	$813,401,411	$620,942,644	$300,253,113	$921,195,757

Docket No. E-01933A-12-0291

DECISION NO. 73912

TUCSON ELECTRIC POWER COJMPANY
TEST YEAR RATES VS. PROPOSED RATES AND REVENUES
TEST PERIOD ENDING DECEMBER 31, 2011

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
	Residential Service R-01						
1	Customer Charge (Single Phase)	3,931,401	$7.00	$27,519,807.00	3,931,401	$10.00	$39,314,010.00
2	Customer Charge (Three Phase)	3,651	$13.00	47,463.00	3,651	$15.00	54,765.00
3	Sum First 500 kWh	865,521,763	$0.046925	40,614,608.75	736,730,680	$0.056200	41,404,264.20
4	Sum 501-1,000 kWh				496,017,382	$0.067200	33,332,368.09
5	Sum 1,001-3,500 kWh	1,180,855,048	$0.068960	81,431,764.12	559,338,750	$0.079800	44,635,232.26
6	Sum>3,500 kWh	25,501,217	$0.088960	2,268,588.23	24,347,732	$0.088200	2,147,469.92
7	Win First 500 kWh				905,934,678	$0.056200	50,913,528.89
8	Win 501-1,000 kWh	777,143,594	$0.047309	36,765,886.29	413,683,007	$0.065200	26,972,132.06
9	Win 1,001-3,500 kWh	510,936,480	$0.067309	34,390,623.50	222,752,388	$0.078100	17,396,961.53
10	Win>3,500 kWh	4,847,097	$0.087309	423,195.23	6,000,583	$0.087100	522,650.74
11	**Subtotal Delivery (Margin) Revenue**			$223,461,936.13			$256,693,382.69
12	Base Power Summer	2,071,878,028	$0.033198	68,782,206.78	1,816,434,544	$0.035111	63,776,833.26
13	Base Power Winter	1,292,927,171	$0.025698	33,225,642.44	1,548,370,656	$0.031532	48,823,223.51
14	TOTAL RESIDENTIAL R-01			$325,469,785.35			$369,293,439.46
15	TOTAL SALES	3,364,805,199			3,364,805,199		
	Residential Service R-02 Consolidated with Residential Service R-01						
16	Customer Charge (Single Phase)	23,820	$5.10	$121,482.00	23,820	$0.00	$0.00
17	Sum First 500 kWh				1,196,221	$0.056200	67,227.62
18	Sum 501-1,000 kWh	3,727,106	$0.017298	64,471.48	66,774	$0.067200	4,487.18
19	Sum 1,001-3,500 kWh			-	59,214	$0.079800	4,725.30
20	Sum>3,500 kWh			-	3,979	$0.088200	350.91
21	Win First 500 kWh				2,165,629	$0.056200	121,708.34
22	Win 501-1,000 kWh			-	148,257	$0.065200	9,666.34
23	Win 1,001-3,500 kWh			-	79,831	$0.078100	6,234.77
24	Win>3,500 kWh			-	7,203	$0.087100	627.36
25	**Subtotal Delivery (Margin) Revenue**			$185,953.48			$215,027.81
26	Base Power Summer	3,727,106	$0.029448	109,755.82	1,326,187	$0.035111	46,563.76
27	Base Power Winter			-	2,400,919	$0.031532	75,705.78
28	TOTAL RESIDENTIAL R-02			$295,709.31			$337,297.35
29	TOTAL SALES	3,727,106			3,727,106		
	Residential Lifeline Service R-01 - Is Now Frozen						
30	Customer Charge (Single Phase)	238,230	$4.90	$1,167,326.66	238,230	$6.90	$1,643,786.52
31	Customer Charge (Three Phase)	69	$12.26	845.94	69	$11.90	821.10
32	Summer (all kWh)	108,919,567	$0.057723	6,287,164.14	93,722,286	$0.061100	5,726,431.67
33	Winter (all kWh)	81,578,627	$0.053272	4,345,856.60	96,775,907	$0.057000	5,516,226.72
34	**Subtotal Delivery (Margin) Revenue**			$11,801,193.35			$12,887,266.01
35	Base Power Summer	108,919,567	$0.033198	3,615,911.77	93,722,286	$0.033198	3,111,392.45
36	Base Power Winter	81,578,627	$0.025698	2,096,407.55	96,775,907	$0.025698	2,486,947.27
37	TOTAL RESIDENTIAL LIFELINE R-XX-01			$17,513,512.67			$18,485,605.73
38	TOTAL SALES	190,498,193			190,498,193		

DECISION NO. 73912

TUCSON ELECTRIC POWER COMPANY
TEST YEAR RATES VS. PROPOSED RATES AND REVENUES
TEST PERIOD ENDING DECEMBER 31, 2011

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
	Residential Lifeline Service R-201A - Is Now Frozen						
1	Customer Charge (Single Phase)	4,218	$4.90	$20,668.46	4,218	$6.90	$29,104.57
2	Mid-Summer (all kWh)	1,397,135	$0.057722	80,645.44	1,397,135	$0.061100	85,364.96
3	Remaining-Summer (all kWh)	1,295,488	$0.040993	53,105.95	899,080	$0.043600	39,199.91
4	Winter (all kWh)	2,104,829	$0.038742	81,545.28	2,501,237	$0.041300	103,301.08
5	**Subtotal Delivery (Margin) Revenue**			**$235,965.14**			**$256,970.52**
6	Base Power Mid Summer	1,397,135	$0.033198	46,382.09	1,397,135	$0.033198	46,382.09
7	Base Power Remain-Summer	1,295,488	$0.033198	43,007.62	899,080	$0.033198	29,847.67
8	Base Power Winter	2,104,829	$0.025698	54,089.89	2,501,237	$0.027198	68,028.64
9	TOTAL LIFELINE R-201			$379,444.75			$401,228.92
10	TOTAL SALES	4,797,453			4,797,453		
	Residential Service R-201AF Consolidated with Residential Service R-201A						
11	Customer Charge (Single Phase)	59,313	$7.00	$415,193.57	59,313	$10.00	$593,133.67
12	Sum First 500 kWh	20,197,805	$0.066139	1,335,862.65	13,531,796	$0.050600	684,708.87
13	Sum 501-1,000 kWh			-	9,105,476	$0.060500	550,881.29
14	Sum 1,001-3,500 kWh	18,091,714	$0.044138	798,532.07	10,267,877	$0.071800	737,233.57
15	Sum>3,500 kWh			-	165,189	$0.079400	13,115.97
16	Win First 500 kWh	30,745,812	$0.033803	1,039,300.67	18,812,952	$0.050600	951,935.36
17	Win 501-1,000 kWh			-	11,090,120	$0.058700	650,990.04
18	Win 1,001-3,500 kWh			-	5,971,603	$0.070300	419,803.70
19	Win>3,500 kWh			-	90,319	$0.078400	7,081.01
20	**Subtotal Delivery (Margin) Revenue**			**$3,588,888.97**			**$4,608,883.48**
21	Base Power Mid-Summer	20,197,805	$0.033198	670,526.74	33,070,337	$0.035111	1,161,132.61
22	Base Power Remain-Summer	18,091,714	$0.033198	600,608.72			
23	Base Power Winter	30,745,812	$0.025698	790,105.87	35,964,994	$0.031532	1,134,048.19
24	**TOTAL R-201A**			**$5,650,130.30**			***$6,904,064.28***
25	TOTAL SALES	69,035,331			69,035,331		
	Residential Service R-201AN Consolidated with Residential Service R-201A						
26	Customer Charge (Single Phase)	65,544	$7.00	$458,808.00	65,544	$10.00	$655,440.00
27	Sum First 500 kWh				12,747,252	$0.050600	645,010.96
28	Sum 501-1,000 kWh	7,410,492	$0.065598	486,113.44	8,523,994	$0.060500	515,701.66
29	Sum 1,001-3,500 kWh	11,446,450	$0.085598	979,793.20	9,612,164	$0.071800	690,153.37
30	Sum>3,500 kWh	107,509	$0.105598	11,352.70	153,507	$0.079400	12,188.42
	Remaining Summer						
31	First 500, or all kWh	7,646,758	$0.022737	173,864.33	-		-
32	501 -3,500, kWh	9,203,000	$0.042737	393,308.63	-		-
33	>3,500 kWh	53,626	$0.062737	3,364.35	-		-
34	Win First 500 kWh	14,115,148	$0.020737	292,705.82	16,425,145	$0.050600	831,112.35
35	Win 501-1,000 kWh	12,338,852	$0.040737	502,647.80	9,653,893	$0.058700	566,683.53
36	Win 1,001-3,500 kWh				5,198,250	$0.070300	365,436.99
37	Win>3,500 kWh	70,315	$0.060737	4,270.75	77,944	$0.078400	6,110.79
38	**Subtotal Delivery (Margin) Revenue**			**$3,306,229.01**			**$4,287,838.07**
39	Base Power Mid-Summer	18,964,450	$0.043166	818,619.45	31,036,917	$0.035111	1,089,737.20
40	Base Power Remain-Summer	16,903,384	$0.023166	391,583.80			
41	Base Power Winter	26,524,315	$0.027033	717,031.81	31,355,232	$0.031532	988,693.19
42	**TOTAL R-201AN**			**$5,233,464.08**			**$6,366,268.46**
43	TOTAL SALES	62,392,149			62,392,149		

TUCSON ELECTRIC POWER COJMPANY
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TEST PERIOD ENDING DECEMBER 31, 2011

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
	Residential Lifeline Service TOU R-21 - Is Now Frozen						
1	Customer Charge	613	$6.86	$4,208.12	613	$8.86	$5,434.98
2	Summer On-peak kWh	109,148	$0.072215	7,882.12	94,070	$0.078800	7,412.68
3	Summer Off-peak kWh	223,428	$0.026967	6,025.17	195,143	$0.030100	5,873.81
4	Winter On-peak kWh	63,890	$0.058320	3,726.08	78,969	$0.065200	5,148.76
5	Winter Off-peak kWh	205,215	$0.029467	6,047.06	233,499	$0.033000	7,705.46
6	**Subtotal Delivery (Margin) Revenue**			$27,888.55			$31,575.70
	Base Power						
7	Summer On-peak kWh	109,148	$0.053198	5,806.45	94,070	$0.053198	5,004.31
8	Summer Off-peak kWh	223,428	$0.023198	5,183.07	195,143	$0.023198	4,526.93
9	Winter On-peak kWh	63,890	$0.040698	2,600.21	78,969	$0.040698	3,213.87
10	Winter Off-peak kWh	205,215	$0.020698	4,247.53	233,499	$0.020698	4,832.96
11	TOTAL LIFELINE TOU R-21F REVENUE			$45,725.82			$49,153.77
12	TOTAL SALES	601,680			601,680		
	Residential Lifeline Service TOU R-70 - Is Now Frozen						
13	Customer Charge	2,375	$6.78	$16,103.20	2,375	$8.78	$20,853.40
14	Summer On-peak	245,865	$0.128473	31,587.01	214,446	$0.139300	29,872.30
15	Summer Shoulder-peak	87,900	$0.068120	5,987.76	87,900	$0.074000	6,504.61
16	Summer Off-peak	847,975	$0.034962	29,646.90	737,025	$0.037900	27,933.24
17	Winter On-peak kWh	185,561	$0.085313	15,830.80	216,981	$0.092500	20,070.70
18	Winter Off-peak kWh	669,640	$0.022921	15,348.83	780,591	$0.024900	19,436.70
19	**Subtotal Delivery (Margin) Revenue**			$114,504.49			$124,670.96
	Base Power						
20	Summer On-peak kWh	245,865	$0.055698	13,694.19	214,446	$0.055698	$11,944.20
21	Summer Shoulder-peak	87,900	$0.048198	4,236.61	87,900	$0.048198	4,236.61
22	Summer Off-peak kWh	847,975	$0.023198	19,671.32	737,025	$0.023198	17,097.50
23	Winter On-peak kWh	185,561	$0.040698	7,551.98	216,981	$0.040698	8,830.67
24	Winter Off-peak kWh	669,640	$0.020698	13,860.22	780,591	$0.020698	16,156.66
25	TOTAL LIFELINE TOU R-70F REVENUE			$173,518.81			$182,936.62
26	TOTAL SALES	2,036,942			2,036,942		
	Residential Service TOU R-21 Frozen Consolidated with Residential TOU R-80						
27	Customer Charge	28,932	$7.00	$202,524.00	28,932	$11.50	$332,718.00
28	Summer On-peak kWh	8,237,292	$0.101271	834,198.77	7,468,625	$0.066800	498,904.12
29	Summer Off-peak kWh	15,589,611	$0.021508	335,301.34	13,949,953	$0.051800	722,607.54
30	Winter On-peak kWh	3,844,450	$0.073292	281,767.45	7,511,294	$0.056800	426,641.52
31	Winter Off-peak kWh	12,839,897	$0.021508	276,160.50	11,581,378	$0.041800	484,101.59
32	**Subtotal Delivery (Margin) Revenue**			$1,929,952.06			$2,464,972.77
	Base Power						
33	Summer On-peak kWh	8,237,292	$0.053198	438,207.45	7,468,625	$0.050669	378,427.74
34	Summer Off-peak kWh	15,589,611	$0.023198	361,647.79	13,949,953	$0.026679	372,170.78
35	Winter On-peak kWh	3,844,450	$0.040698	156,461.44	7,511,294	$0.032893	247,069.01
36	Winter Off-peak kWh	12,839,897	$0.020698	265,760.18	11,581,378	$0.027092	313,762.68
37	TOTAL TOU R-21F REVENUE			$3,152,028.91			$3,776,402.99
38	TOTAL SALES	40,511,249			40,511,249		

TUCSON ELECTRIC POWER COMPANY
TEST YEAR RATES VS. PROPOSED RATES AND REVENUES
TEST PERIOD ENDING DECEMBER 31, 2011

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
	Residential Service TOU R-70 Consolidated with Residential TOU R-80						
1	Customer Charge	49,320	$7.00	$345,240.00	49,320	$11.50	$567,180.00
2	Summer On-peak	6,662,407	$0.174747	1,164,235.63	11,348,439	$0.066800	758,075.71
3	Summer Shoulder-peak	2,577,159	$0.102823	264,991.23	-	$0.000000	-
4	Summer Off-peak	27,114,005	$0.041176	1,116,446.26	21,204,659	$0.051800	1,098,401.36
5	Winter On-peak kWh	5,967,824	$0.025762	153,743.09	10,594,826	$0.056800	601,786.13
6	Winter Off-peak kWh	17,165,126	$0.023098	396,480.07	16,338,596	$0.041800	682,953.33
7	**Subtotal Delivery (Margin) Revenue**			$3,441,136.29			$3,708,396.53
	Base Power						
8	Summer On-peak kWh	6,662,407	$0.055698	$371,082.74	11,348,439	$0.050669	575,014.05
9	Summer Shoulder-peak	2,577,159	$0.048198	124,213.92	-	$0.000000	-
10	Summer Off-peak kWh	27,114,005	$0.023198	628,990.68	21,204,659	$0.026679	565,719.11
11	Winter On-peak kWh	5,967,824	$0.040698	242,878.52	10,594,826	$0.032893	348,495.62
12	Winter Off-peak kWh	17,165,126	$0.020698	355,283.77	16,338,596	$0.027092	442,645.26
13	**TOTAL TOU R-70F REVENUE**			$5,163,585.92			$5,640,270.56
14	TOTAL SALES	59,486,521			59,486,521		
	Residential Time-of-Use R-70N-B Consolidated with Residential TOU R-80						
15	Customer Charge	2,424	$8.00	$19,392.00	2,424	$11.50	$27,876.00
	Summer On-peak						
16	First 500, kWh	93,863	$0.079947	7,504.08	523,087	$0.066800	34,942.22
17	501 -3,500, kWh	176,848	$0.096571	17,078.41			-
18	>3,500 kWh	2,267	$0.116571	264.23			-
	Summer Shoulder-peak						
19	First 500, kWh	143,827	$0.050121	7,208.74			-
20	501 -3,500, kWh	281,334	$0.070121	19,727.44			-
21	>3,500 kWh	3,679	$0.090121	331.54			-
	Summer Off-peak						
22	First 500, kWh	349,097	$0.041217	14,388.72	979,031	$0.051800	50,713.81
23	501 -3,500, kWh	675,543	$0.057841	39,074.11			-
24	>3,500 kWh	8,856	$0.077841	689.33			-
	Winter On-peak						
25	First 500, kWh	162,731	$0.067066	10,913.71	479,959	$0.056800	27,261.67
26	501 -3,500, kWh	139,508	$0.085478	11,924.83			-
27	>3,500 kWh	507	$0.105478	53.52			-
	Winter Off-peak						
28	First 500, kWh	366,538	$0.037066	13,586.10	739,514	$0.041800	30,911.70
29	501 -3,500, kWh	315,870	$0.055478	17,523.86			-
30	>3,500 kWh	1,123	$0.075478	84.78			-
31	**Subtotal Delivery (Margin) Revenue**			$179,745.40			$171,705.40
	Base Power						
32	Summer On-peak	272,978	$0.055440	15,133.91	523,087	$0.050669	26,504.30
33	Summer Shoulder-peak	428,840	$0.034876	14,956.22	-	$0.00	-
34	Summer Off-peak	1,033,496	$0.019865	20,530.40	979,031	$0.026679	26,119.57
35	Winter On-peak kWh	302,746	$0.042874	12,979.93	479,959	$0.032893	15,787.29
36	Winter Off-peak kWh	683,532	$0.025086	17,147.08	739,514	$0.027092	20,034.92
37	**TOTAL TOU R-70N-B REVENUE**			$260,492.93			$260,151.48
38	TOTAL SALES	2,721,591			2,721,591		

TUCSON ELECTRIC POWER COJMPANY
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TEST PERIOD ENDING DECEMBER 31, 2011

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
	Residential Time-of-Use R-70N-C Consolidated with Residential TOU R-80						
1	Customer Charge	7,812	$8.00	$62,496.00	7,812	$11.50	$89,838.00
	Summer On-peak						
2	First 500, kWh	413,264	$0.077356	31,968.49	1,503,228	$0.066800	100,415.60
3	501 -3,500, kWh	684,298	$0.096354	65,934.87			-
4	>3,500 kWh	16,766	$0.116354	1,950.81			-
	Summer Shoulder-peak						
5	First 500, kWh	255,582	$0.049507	12,653.09			-
6	501 -3,500, kWh	429,716	$0.069507	29,868.29			-
7	>3,500 kWh	10,408	$0.089507	931.58			-
	Summer Off-peak						
8	First 500, kWh	1,170,661	$0.038229	44,753.18	2,814,086	$0.051800	145,769.65
9	501 -3,500, kWh	1,931,943	$0.057227	110,559.31			-
10	>3,500 kWh	46,780	$0.077227	3,612.69			-
	Winter On-peak						
11	First 500, kWh	503,061	$0.066452	33,429.40	1,391,693	$0.056800	79,048.19
12	501 -3,500, kWh	376,700	$0.084864	31,968.29			-
13	>3,500 kWh	2,023	$0.104864	212.18			-
	Winter Off-peak						
14	First 500, kWh	1,148,576	$0.036452	41,867.90	2,144,159	$0.041800	89,625.85
15	501 -3,500, kWh	858,787	$0.054864	47,116.49			-
16	>3,500 kWh	4,599	$0.074864	344.33			-
	Subtotal Delivery (Margin) Revenue			$519,666.90			$504,697.28
17	**Base Power**						
18	Summer On-peak	1,114,329	$0.054330	60,541.49	1,503,228	$0.050669	76,167.04
19	Summer Shoulder-peak	695,706	$0.034177	23,777.15	-	$0.000000	-
20	Summer Off-peak	3,149,384	$0.019467	61,309.06	2,814,086	$0.026679	75,077.00
21	Winter On-peak kWh	881,784	$0.042015	37,048.17	1,391,693	$0.032893	45,776.97
22	Winter Off-peak kWh	2,011,963	$0.024585	49,464.10	2,144,159	$0.027092	58,089.56
23	***TOTAL TOU R-70N-C REVENUE***			$751,806.87			$759,807.85
24	TOTAL SALES	7,853,166			7,853,166		

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TUCSON ELECTRIC POWER COJMPANY
TEST YEAR RATES VS. PROPOSED RATES AND REVENUES
TEST PERIOD ENDING DECEMBER 31, 2011

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
	Residential Time-of-Use R-70N-D Consolidated with Residential TOU R-80						
1	Customer Charge	5,424	$8.00	$43,392.00	5,424	$11.50	$62,376.00
	Summer On-peak						
2	First 500, kWh	200,869	$0.091873	18,454.43	1,112,090	$0.066800	74,287.60
3	501 -3,500, kWh	354,929	$0.107334	38,095.99			-
4	>3,500 kWh	6,150	$0.127334	783.16			-
	Summer Shoulder-peak						
5	First 500, kWh	180,379	$0.049814	8,985.40			-
6	501 -3,500, kWh	325,516	$0.069814	22,725.59			-
7	>3,500 kWh	5,713	$0.089814	513.07			-
	Summer Off-peak						
8	First 500, kWh	919,875	$0.042073	38,701.91	2,081,044	$0.051800	107,798.09
9	501 -3,500, kWh	1,637,031	$0.057534	94,184.94			-
10	>3,500 kWh	28,367	$0.077534	2,199.37			-
	Winter On-peak						
11	First 500, kWh	289,183	$0.068737	19,877.56	1,021,079	$0.056800	57,997.31
12	501 -3,500, kWh	236,708	$0.085171	20,160.66			-
13	>3,500 kWh	1,062	$0.105171	111.73			-
	Winter Off-peak						
14	First 500, kWh	877,051	$0.038737	33,974.32	1,572,514	$0.041800	65,731.07
15	501 -3,500, kWh	720,607	$0.055171	39,756.60			-
16	>3,500 kWh	3,287	$0.075171	247.08			-
	Subtotal Delivery (Margin) Revenue			$382,163.81			$368,190.08
17	**Base Power**						
18	Summer On-peak	561,949	$0.058271	32,745.31	1,112,090	$0.050669	56,348.48
19	Summer Shoulder-peak	511,608	$0.036656	18,753.50	-	$0.000000	-
20	Summer Off-peak	2,585,273	$0.020880	53,980.50	2,081,044	$0.026679	55,520.18
21	Winter On-peak kWh	526,953	$0.045063	23,746.09	1,021,079	$0.032893	33,586.37
22	Winter Off-peak kWh	1,600,945	$0.026368	42,213.71	1,572,514	$0.027092	42,602.54
23	***TOTAL TIME OF USE R-70N-D REVENUE***			$553,602.92			$556,247.64
24	TOTAL SALES	5,786,727			5,786,727		
	Residential Lifeline Service TOU R-201B - Is Now Frozen						
25	Customer Charge (Single Phase)	159	$6.78	$1,081.31	159	$8.78	$1,400.28
	Summer						
26	Mid-Summer On-peak	8,244	$0.128473	1,059.11	8,244	$0.136900	1,128.58
27	Mid-Summer Shoulder-peak	3,900	$0.068120	265.69	3,900	$0.074700	291.35
28	Mid-Summer Off-peak	32,255	$0.034962	1,127.70	32,255	$0.038300	1,235.37
29	*Remaining-Summer* On-peak	7,834	$0.090717	710.66	5,483	$0.099500	545.59
30	Remaining-Summer Shoulder-peak	2,703	$0.044275	119.66	2,703	$0.048600	131.35
31	Remaining-Summer Off-peak	29,775	$0.023038	685.96	20,657	$0.025300	522.61
32	Winter On-peak	15,413	$0.059481	916.76	17,763	$0.065200	1,158.16
33	Winter Off-peak	51,295	$0.013975	716.84	60,413	$0.015300	924.32
34	**Subtotal Delivery (Margin) Revenue**			$6,683.68			$7,337.60
	Base Power						
35	Mid-Summer On-peak	8,244	$0.055698	459.16	8,244	$0.055698	459.16
36	Mid-Summer Shoulder-peak	3,900	$0.048198	187.99	3,900	$0.048198	187.99
37	Mid-Summer Off-peak	32,255	$0.023198	748.25	32,255	$0.023198	748.25
38	Remaining-Summer On-peak	7,834	$0.055698	436.33	5,483	$0.055698	305.41
39	Remaining-Summer Shoulder-peak	2,703	$0.048198	130.27	2,703	$0.048198	130.27
40	Remaining-Summer Off-peak	29,775	$0.023198	690.72	20,657	$0.023198	479.19
41	Winter On-peak	15,413	$0.040698	627.26	17,763	$0.040698	722.92
42	Winter Off-peak	51,295	$0.020698	1,061.70	60,413	$0.020698	1,250.43
43	TOTAL LIFELINE R-XX-201B			$11,025.36			$11,621.23
44	TOTAL SALES	151,418			151,418		

TUCSON ELECTRIC POWER COJMPANY
TEST YEAR RATES VS. PROPOSED RATES AND REVENUES
TEST PERIOD ENDING DECEMBER 31, 2011

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
	Residential Service TOU R-201BF Consolidated with Residential TOU Service R-201B						
1	Customer Charge (Single Phase)	5,927	$7.00	$41,486.05	5,927	$11.50	$68,155.66
	Summer						
2	Mid-Summer On-peak	412,357	$0.166303	68,576.29	1,250,513	$0.056800	71,029.15
3	Mid-Summer Shoulder-peak	172,389	$0.093043	16,039.62			-
4	Mid-Summer Off-peak	1,624,561	$0.031395	51,003.10	2,339,501	$0.044000	102,938.06
5	Remaining-Summer On-peak	364,035	$0.124945	45,484.39			-
6	Remaining-Summer Shoulder-peak	119,418	$0.067767	8,092.58			-
7	Remaining-Summer Off-peak	1,456,605	$0.018756	27,320.08			-
8	Winter On-peak	773,032	$0.075935	58,700.22	1,564,449	$0.048300	75,562.88
9	Winter Off-peak	2,639,143	$0.006499	17,151.79	2,407,078	$0.035500	85,451.27
10	**Subtotal Delivery (Margin) Revenue**			**$333,854.12**			**$403,137.02**
11	Mid-Summer On-peak	412,357	$0.055698	22,967.49	1,250,513	$0.050669	63,362.25
12	Mid-Summer Shoulder-peak	172,389	$0.048198	8,308.82			
13	Mid-Summer Off-peak	1,624,561	$0.023198	37,686.57	2,339,501	$0.026679	62,415.55
14	Remaining-Summer On-peak	364,035	$0.055698	20,276.04			
15	Remaining-Summer Shoulder-peak	119,418	$0.048198	5,755.69			
16	Remaining-Summer Off-peak	1,456,605	$0.023198	33,790.31			
17	Winter On-peak	773,032	$0.040698	31,460.87	1,564,449	$0.032893	51,459.42
18	Winter Off-peak	2,639,143	$0.020698	54,624.99	2,407,078	$0.027092	65,212.56
19	**TOTAL TOU R-201BF**			**$548,724.91**			**$645,586.80**
20	TOTAL SALES	7,561,541			7,561,541		
	Residential Service TOU R-201CF Consolidated with Residential TOU Service R-201B						
21	Customer Charge (Single Phase)	2,464	$7.00	$17,248.38	2,464	$11.50	$28,336.62
	Summer						
22	Mid-Summer On-peak	154,320	$0.161981	24,996.89	346,597	$0.056800	19,686.73
23	Mid-Summer Shoulder-peak	43,356	$0.090057	3,904.52			-
24	Mid-Summer Off-peak	407,895	$0.028409	11,587.89	649,452	$0.044000	28,575.88
25	Remaining-Summer On-peak	148,960	$0.112200	16,713.28			-
26	Remaining-Summer Shoulder-peak	32,007	$0.058618	1,876.18			-
27	Remaining-Summer Off-peak	398,805	$0.012688	5,060.04			-
28	Winter On-peak	315,061	$0.066272	20,879.75	478,871	$0.048300	23,129.49
29	Winter Off-peak	711,416	$0.001201	854.41	736,900	$0.035500	26,159.96
30	**Subtotal Delivery (Margin) Revenue**			**$103,121.34**			**$125,888.68**
31	Mid-Summer On-peak	154,320	$0.055698	8,595.31	346,597	$0.050669	17,561.74
32	Mid-Summer Shoulder-peak	43,356	$0.048198	2,089.68			
33	Mid-Summer Off-peak	407,895	$0.023198	9,462.35	649,452	$0.026679	17,326.72
34	Remaining-Summer On-peak	148,960	$0.055698	8,296.76			
35	Remaining-Summer Shoulder-peak	32,007	$0.048198	1,542.67			
36	Remaining-Summer Off-peak	398,805	$0.023198	9,251.49			
37	Winter On-peak	315,061	$0.040698	12,822.37	478,871	$0.032893	15,751.52
38	Winter Off-peak	711,416	$0.020698	14,724.89	736,900	$0.027092	19,964.10
39	**TOTAL TOU R-201CF**			**$169,906.85**			**$196,492.76**
40	TOTAL SALES	2,211,821			2,211,821		

TUCSON ELECTRIC POWER COJMPANY
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TEST PERIOD ENDING DECEMBER 31, 2011

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
	Residential Service TOU R-201BN Consolidated with Residential TOU Service R-201B						
1	Customer Charge	696	$8.00	$5,568.00	696	$11.50	$8,004.00
	MID-Summer On-peak						
2	First 500, kWh	11,829	$0.110962	1,312.59	142,511	$0.056800	8,094.60
3	501 -3,500, kWh	24,718	$0.130962	3,237.18			-
4	>3,500 kWh	277	$0.150962	41.81			-
	MID-Summer Shoulder-peak						
5	First 500, kWh	10,819	$0.043962	475.64			-
6	501 -3,500, kWh	22,549	$0.063962	1,442.27			-
7	>3,500 kWh	249	$0.083962	20.92			-
	MID-Summer Off-peak						
8	First 500, kWh	57,234	$0.020362	1,165.40	266,449	$0.044000	11,723.77
9	501 -3,500, kWh	118,631	$0.040362	4,788.20			-
10	>3,500 kWh	1,294	$0.060362	78.09			-
	REMAIN-Summer On-peak						
11	First 500, kWh	14,825	$0.047962	711.02			-
12	501 -3,500, kWh	22,011	$0.067962	1,495.90			-
13	>3,500 kWh	41	$0.087962	3.59			-
	REMAIN-Summer Shoulder-peak						
14	First 500, kWh	11,461	$0.024162	276.93			-
15	501 -3,500, kWh	18,526	$0.044162	818.14			-
16	>3,500 kWh	37	$0.064162	2.37			-
	REMAIN-Summer Off-peak						
17	First 500, kWh	62,102	$0.016462	1,022.32			-
18	501 -3,500, kWh	100,213	$0.036462	3,653.98			-
19	>3,500 kWh	198	$0.056462	11.16			-
	Winter On-peak						
20	First 500, kWh	41,562	$0.047962	1,993.40	172,825	$0.048300	8,347.44
21	501 -3,500, kWh	53,991	$0.067962	3,669.35			-
22	>3,500 kWh	93	$0.087962	8.17			-
	Winter Off-peak						
23	First 500, kWh	119,596	$0.016462	1,968.79	266,031	$0.035500	9,444.11
24	501 -3,500, kWh	155,274	$0.036462	5,661.59			-
25	>3,500 kWh	286	$0.056462	16.17			-
26	**Subtotal Delivery (Margin) Revenue**			$39,442.95			$45,613.92
	Base Power						
27	Mid-Summer On-peak	36,825	$0.077356	2,848.60	142,511	$0.050669	7,220.87
28	Mid-Summer Shoulder-peak	33,617	$0.038166	1,283.04			-
29	Mid-Summer Off-peak	177,159	$0.033166	5,875.66	266,449	$0.026679	7,108.60
30	Remaining-Summer On-peak	36,876	$0.057356	2,115.08			-
31	Remaining-Summer Shoulder-peak	30,024	$0.018166	545.42			-
32	Remaining-Summer Off-peak	162,513	$0.013166	2,139.65			-
33	Winter On-peak	95,646	$0.061223	5,855.74	172,825	$0.032893	5,684.72
34	Winter Off-peak	275,156	$0.017033	4,686.73	266,031	$0.027092	7,207.32
35	TOTAL TOU R-201BN REVENUE			$64,792.86			$72,835.44
36	TOTAL SALES	847,816			847,816		

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TUCSON ELECTRIC POWER COJMPANY
TEST YEAR RATES VS. PROPOSED RATES AND REVENUES
TEST PERIOD ENDING DECEMBER 31, 2011

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
	Residential Service TOU R-201CN Consolidated with Residential TOU Service R-201B						
1	Customer Charge	329	$8.00	$2,632.00	329	$11.50	$3,783.50
	MID-Summer On-peak						
2	First 500, kWh	3,953	$0.099462	393.15	24,024	$0.056800	1,364.56
3	501 -3,500, kWh	3,816	$0.117162	447.04			-
4	>3,500 kWh	-	$0.134862	-			-
	MID-Summer Shoulder-peak						
5	First 500, kWh	2,040	$0.040512	82.65			-
6	501 -3,500, kWh	2,430	$0.058212	141.44			-
7	>3,500 kWh	-	$0.075912	-			-
	MID-Summer Off-peak						
8	First 500, kWh	14,980	$0.019626	293.99	45,026	$0.044000	1,981.17
9	501 -3,500, kWh	15,497	$0.037326	578.45			-
10	>3,500 kWh	-	$0.055026	-			-
	REMAIN-Summer On-peak						
11	First 500, kWh	3,445	$0.044052	151.77			-
12	501 -3,500, kWh	3,485	$0.061752	215.18			-
13	>3,500 kWh	-	$0.079452	-			-
	REMAIN-Summer Shoulder-peak						
14	First 500, kWh	2,616	$0.022989	60.14			-
15	501 -3,500, kWh	2,711	$0.040689	110.31			-
16	>3,500 kWh	-	$0.058389	-			-
	REMAIN-Summer Off-peak						
17	First 500, kWh	14,880	$0.016175	240.68			-
18	501 -3,500, kWh	14,818	$0.033875	501.97			-
19	>3,500 kWh	-	$0.051575	-			-
	Winter On-peak						
20	First 500, kWh	11,128	$0.044052	490.19	33,302	$0.048300	1,608.49
21	501 -3,500, kWh	7,870	$0.061752	486.00			-
22	>3,500 kWh	-	$0.079452	-			-
	Winter Off-peak						
23	First 500, kWh	29,014	$0.016175	469.30	51,137	$0.035500	1,815.37
24	501 -3,500, kWh	20,808	$0.033875	704.86			-
25	>3,500 kWh	-	$0.051575	-			-
26	**Subtotal Delivery (Margin) Revenue**			$7,999.13			$10,553.08
	Base Power						
27	Mid-Summer On-peak	7,768	$0.078903	612.95	24,024	$0.050669	1,217.26
28	Mid-Summer Shoulder-peak	4,470	$0.038929	174.01	-		-
29	Mid-Summer Off-peak	30,477	$0.033829	1,031.00	45,026	$0.026679	1,201.26
30	Remaining-Summer On-peak	6,930	$0.058503	405.41	-		-
31	Remaining-Summer Shoulder-peak	5,327	$0.018529	98.71	-		-
32	Remaining-Summer Off-peak	29,698	$0.013429	398.81	-		-
33	Winter On-peak	18,998	$0.062447	1,186.36	33,302	$0.032893	1,095.40
34	Winter Off-peak	49,822	$0.017374	865.60	51,137	$0.027092	1,385.40
35	**TOTAL TOU R-201CN REVENUE**			$12,771.99			$15,452.41
36	TOTAL SALES	153,489			153,489		
37	**RESIDENTIAL STANDARD SUBTOTAL**						$401,787,904.20
38	**RESIDENTIAL TIME OF USE SUBTOTAL**						$12,166,959.53
39	**RESIDENTIAL COMMUNITY SOLAR**						$362,756.94
40	**RESIDENTIAL LIFELINE DISCOUNT**						($2,493,089.80)
41	**RESIDENTIAL TOTAL REVENUE**						$411,824,530.88

TUCSON ELECTRIC POWER COJMPANY
TEST YEAR RATES VS. PROPOSED RATES AND REVENUES
TEST PERIOD ENDING DECEMBER 31, 2011

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
	Small General Service SGS-10						
1	Customer Charge (Single Phase	206,171	$8.00	$1,649,368.00	206,171	$15.50	$3,195,650.50
2	Customer Charge (Three Phase	212,653	$14.00	2,977,142.00	212,653	$20.50	4,359,386.50
	Summer						
3	First 500, kWh	83,218,214	$0.056236	4,679,859.46	70,402,123	$0.076800	5,406,883.03
4	≥ 501 kWh	924,529,471	$0.085145	78,719,061.80	794,353,073	$0.097600	77,528,859.89
	Winter						
5	First 500, kWh	85,492,289	$0.051252	4,381,650.82	98,308,380	$0.056800	5,583,916.00
6	≥ 501 kWh	676,979,742	$0.080145	54,256,541.39	807,156,140	$0.078800	63,603,903.82
7	Primary Metering Discount			(4,847.65)			(4,847.65)
8	**Subtotal Delivery (Margin) Revenue**			$146,658,775.81			$159,673,752.08
9	Base Power Summer	1,007,747,684	$0.031550	31,794,439.45	864,755,195	$0.035111	30,362,419.67
10	Base Power Winter	762,472,031	$0.024222	18,468,597.53	905,464,520	$0.031532	28,551,107.25
11	**TOTAL General Service SGS-10**			$196,921,812.79			$218,587,279.00
12	TOTAL SALES	1,770,219,715			1,770,219,715		
	Municipal Service PS-40 Consolidated with Small General Service SGS-10						
13	Customer Charge (Single Phase	8,849	$0.00	$0.00	8,849	$15.50	$137,159.50
	Summer						
14	First 500, kWh	64,734,411	$0.057530	3,724,170.65	4,420,553	$0.076800	339,498.47
15	≥ 501 kWh			-	50,114,177	$0.097600	4,891,143.64
	Winter						
16	First 500, kWh	53,570,309	$0.053159	2,847,744.07	6,912,295	$0.056800	392,618.38
17	≥ 501 kWh			-	56,857,695	$0.078800	4,480,386.36
18	**Subtotal Delivery (Margin) Revenue**			$6,571,914.72			$10,240,806.35
19	Base Power Summer	64,734,411	0.032245	2,087,361.07	54,534,730	$0.035111	1,914,768.89
20	Base Power Winter	53,570,309	$0.024745	1,325,597.30	63,769,990	$0.031532	2,010,795.33
21	**TOTAL PS-40 REVENUE**			$9,984,873.09			$14,166,370.58
22	TOTAL SALES	118,304,720			118,304,720		
	SGS Time of Use SGS-76F Consolidated with SGS TOU 76						
14	Customer Charge	9,936	$8.00	$79,488.00	9,936	$17.50	$173,880.00
15	Summer On-peak	9,825,216	$0.207220	2,035,981.36	16,433,218	$0.098700	1,621,958.60
16	Summer Shoulder-peak	3,497,021	$0.119884	419,236.89		-	-
17	Summer Off-peak	46,772,467	$0.042825	2,003,030.91	35,012,373	$0.084500	2,958,545.54
18	Winter On-peak kWh	10,425,706	$0.130159	1,356,999.48	23,274,964	$0.081000	1,885,272.08
19	Winter Off-peak kWh	39,244,555	$0.027411	1,075,732.50	35,044,410	$0.064500	2,260,364.44
20	**Subtotal Delivery (Margin) Revenue**			$6,970,469.14			$8,900,020.66
21	**Base Power**						
22	Summer On-peak kWh	9,825,216	$0.056123	551,420.62	16,433,218	$0.050669	832,654.71
23	Summer Shoulder-peak	3,497,021	$0.056123	196,263.32	-	-	-
24	Summer Off-peak kWh	46,772,467	$0.023623	1,104,905.99	35,012,373	$0.026679	934,095.11
25	Winter On-peak kWh	10,425,706	$0.038809	404,611.23	23,274,964	$0.032893	765,583.39
26	Winter Off-peak kWh	39,244,555	$0.018809	738,150.84	35,044,410	$0.027092	949,423.15
27	**TOTAL TOU SGS-76F REVENUE**			$9,965,821.15			$12,381,777.02
28	TOTAL SALES	109,764,966			109,764,965		

TUCSON ELECTRIC POWER COJMPANY
TEST YEAR RATES VS. PROPOSED RATES AND REVENUES
TEST PERIOD ENDING DECEMBER 31, 2011

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
	SGS Time of Use SGS-76N Consolidated with SGS TOU 76						
1	Customer Charge	1,152	$9.00	$10,368.00	1,152	$17.50	$20,160.00
	Summer On-peak						
2	First 500, kWh	53,632	$0.153751	8,245.99	2,195,464	$0.098700	216,692.26
3	501 -3,500, kWh	1,659,304	$0.182660	303,088.41			-
	Summer Shoulder-peak						
4	First 500, kWh	44,206	$0.041416	1,830.82			-
5	501 -3,500, kWh	1,358,337	$0.070325	95,525.07			-
	Summer Off-peak						
6	First 500, kWh	150,763	$0.027416	4,133.31	4,658,430	$0.084500	393,637.30
7	501 -3,500, kWh	4,722,873	$0.056325	266,015.85			-
	Winter On-peak						
8	First 500, kWh	86,798	$0.088434	7,675.93	2,777,047	$0.081000	224,940.85
9	501 -3,500, kWh	1,918,001	$0.117327	225,033.25			-
	Winter Off-peak						
10	First 500, kWh	165,442	$0.027415	4,535.58	4,194,613	$0.064500	270,552.51
11	501 -3,500, kWh	3,666,198	$0.056308	206,436.27			-
	Subtotal Delivery (Margin) Revenue			$1,132,888.48			$1,125,982.91
12	**Base Power**						
13	Summer On-peak	1,712,936	$0.052000	89,072.66	2,195,464	$0.050669	111,241.95
14	Summer Shoulder-peak	1,402,543	$0.032000	44,881.37	-	-	-
15	Summer Off-peak	4,873,636	$0.022000	107,220.00	4,658,430	$0.026679	124,282.24
16	Winter On-peak kWh	2,004,799	$0.032000	64,153.57	2,777,047	$0.032893	91,345.42
17	Winter Off-peak kWh	3,831,639	$0.022000	84,296.07	4,194,613	$0.027092	113,640.44
18	**TOTAL TOU SGS 76N REVENUE**			$1,522,512.15			$1,566,492.97
19	TOTAL SALES	13,825,553			13,825,553		
	GS Mobile Home Parks GS-11 Frozen						
20	Customer Charge Single Pha	3,722	$8.00	$29,772.94	3,722	$15.50	$57,685.08
21	Customer Charge Three Pha	346	$14.00	4,849.35	346	$20.50	7,100.83
22	Summer kWh	30,805,210	$0.067290	2,072,882.60	26,876,589	$0.082000	2,203,880.28
23	Winter kWh	27,809,489	$0.052751	1,466,978.38	31,738,111	$0.062000	1,967,762.88
24	Primary Metering Discount			(3,284.98)			(3,284.98)
25	Transformer Owned Discount			(3,430.22)			(3,430.22)
26	**Subtotal Delivery (Margin) Revenue**			$3,567,768.07			$4,229,713.87
27	Base Power Summer	30,805,210	$0.028730	885,033.69	26,876,589	$0.035111	943,663.91
28	Base Power Winter	27,809,489	$0.028730	798,966.63	31,738,111	$0.031532	1,000,766.12
29	**TOTAL GS-11 REVENUE**			$5,251,768.40			$6,174,143.90
30	TOTAL SALES	58,614,700			58,614,700		

TUCSON ELECTRIC POWER COJMPANY
TEST YEAR RATES VS. PROPOSED RATES AND REVENUES
TEST PERIOD ENDING DECEMBER 31, 2011

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
1	**Water Pumping GS-43**						
2	Customer Charge	4,063	$ -	$0.00	4,063	$15.50	$62,976.50
3	Summer kWh	29,185,229	$0.060347	1,761,240.99	24,321,024	$0.0680	1,653,829.62
4	Winter kWh	20,994,203	$0.055731	1,170,027.93	25,858,408	$0.0480	1,241,203.58
5	**Subtotal Delivery (Margin) Revenue**			$2,931,268.92			$2,958,009.70
6	Base Power Summer	29,185,229	$0.029868	871,704.41	24,321,024	$0.035111	853,935.47
7	Base Power Winter	20,994,203	$0.022368	469,598.33	25,858,408	$0.031532	815,367.32
8	**TOTAL GS-43 REVENUE**			$4,272,571.66			$4,627,312.48
9	TOTAL SALES	50,179,432			50,179,432		
	Water Pumping GS-31 Consolidated with Water Pumping GS-43						
10	Customer Charge	365	$ -	$0.00	365	$15.50	$5,657.50
11	Summer kWh	11,400,116	$0.025700	292,982.97	9,620,168	$0.042000	404,047.07
12	Winter kWh	2,773,403	$0.024205	67,130.22	4,553,351	$0.027000	122,940.47
13	**Subtotal Delivery (Margin) Revenue**			$360,113.20			$532,645.03
14	Base Power Summer	11,400,116	$0.028730	327,525.33	9,620,168	$0.031310	301,207.47
15	Base Power Winter	2,773,403	$0.028730	79,679.87	4,553,351	$0.028420	129,406.22
16	**TOTAL GS-31 REVENUE**			$767,318.39			$963,258.72
17	TOTAL SALES	14,173,519			14,173,519		
	Water Pumping GS-45 Consolidated with Water Pumping GS-43						
18	Customer Charge	1,382	$ -	$0.00	1,382	$15.50	$21,421.00
19	Summer kWh	25,751,439	$0.027281	702,525.00	21,459,532	$0.042000	901,300.35
20	Winter kWh	17,480,298	$0.025911	452,931.99	21,772,204	$0.027000	587,849.51
21	**Subtotal Delivery (Margin) Revenue**			$1,155,456.99			$1,510,570.87
22	Base Power Summer	25,751,439	$0.029868	769,143.97	21,459,532	$0.031310	671,897.95
23	Base Power Winter	17,480,298	$0.022368	390,999.30	21,772,204	$0.028420	618,766.04
24	**TOTAL GS-45 REVENUE**			$2,315,600.26			$2,801,234.86
25	TOTAL SALES	43,231,736			43,231,736		
	LARGE GENERAL SERVICE LGS-13						
26	Customer Charge	6,420	$371.88	$2,387,469.60	6,420	$775.00	$4,975,500.00
27	ALL kW	2,571,910	$10.35	26,624,414.03	2,719,841	$15.25	41,477,573.96
28	Summer kWh	582,034,661	$0.025656	14,932,681.28	494,868,791	$0.0192	9,501,480.79
29	Winter kWh	463,029,153	$0.023910	11,071,027.04	550,195,023	$0.0134	7,372,613.31
30	Primary Metering Discount			(35,627.70)			(35,627.70)
31	Transformer Owned Discount			(27,316.74)			(27,316.74)
32	**Subtotal Delivery (Margin) Revenue**			$54,952,647.51			$63,264,223.62
33	**Base Power**						
34	Summer kWh	582,034,661	$0.032554	18,947,556.37	494,868,791	$0.035111	17,375,338.13
35	Winter kWh	463,029,153	$0.025054	11,600,732.40	550,195,023	$0.031532	17,348,749.46
36	**TOTAL LGS-13 REVENUE**			$85,500,936.28			$97,988,311.22
37	TOTAL SALES	1,045,063,814			1,045,063,814		

TUCSON ELECTRIC POWER COJMPANY
TEST YEAR RATES VS. PROPOSED RATES AND REVENUES
TEST PERIOD ENDING DECEMBER 31, 2011

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
	LGS Time of Use LGS-85F Consolidated with LGS TOU 85				-		
1	Customer Charge	87	$371.88	$32,262.41	87	$950.00	$82,417.16
2	Summer On-Peak kW	19,345	$17.32	335,057.12	16,153	$14.55	235,025.85
3	Summer Shoulder-Peak kW	0	$8.66				
4	Summer Off-peak kW		$11.46	-	-	$10.92	-
5	Winter On-Peak kW	17,037	$9.65	164,338.97	20,403	$11.59	236,467.90
6	Winter Off-peak kW		$4.82	-	-	$9.10	-
7	Summer On-peak	1,276,087	$0.083765	106,891.46	1,698,736	$0.008600	14,609.13
8	Summer Shoulder-peak	437,006	$0.053910	23,558.99		$0.00	-
9	Summer Off-peak	6,281,523	$0.005693	35,760.71	5,082,830	$0.006000	30,496.98
10	Winter On-peak kWh	1,381,684	$0.053910	74,486.59	2,613,835	$0.003000	7,841.50
11	Winter Off-peak kWh	5,266,449	$0.005693	29,981.90	5,247,350	$0.000500	2,623.67
12	**Subtotal Delivery (Margin) Revenue**			**$802,338.15**			**$609,482.19**
	Base Power						
13	Summer On-peak kWh	1,276,087	$0.056452	72,037.68	1,698,736	$0.050669	86,073.27
14	Summer Shoulder-peak	437,006	$0.056452	24,669.86	-	$0.00	-
15	Summer Off-peak kWh	6,281,523	$0.023952	150,455.05	5,082,830	$0.026679	135,604.81
16	Winter On-peak kWh	1,381,684	$0.039341	54,356.84	2,613,835	$0.032893	85,976.86
17	Winter Off-peak kWh	5,266,449	$0.019341	101,858.40	5,247,350	$0.027092	142,161.20
18	**TOTAL TOU LGS-85F REVENUE**			**$1,205,715.98**			**$1,059,298.33**
19	TOTAL SALES	14,642,750			14,642,750		
	LGS Time of Use LGS-85AF Consolidated with LGS TOU 85						
20	Customer Charge	201	$371.88	$74,839.03	201	$950.00	$191,182.84
21	Summer On-Peak kW	33,507	$7.95	266,377.21	28,787	$14.55	418,848.43
22	Summer Shoulder-Peak kW	-	$5.26	-	-		-
23	Summer Off-peak kW		$3.98	-	-	$10.92	-
24	Winter On-Peak kW	30,755	$5.26	161,697.91	35,746	$11.59	414,296.16
25	Winter Off-peak kW	-	$2.63	-	-	$9.10	-
26	Summer On-peak	2,599,727	$0.053290	138,539.47	6,641,029	$0.008600	57,112.85
27	Summer Shoulder-peak	922,051	$0.044980	41,473.87	-	$0.00	-
28	Summer Off-peak	13,913,940	$0.036667	510,182.42	8,319,627	$0.006000	49,917.76
29	Winter On-peak kWh	2,874,352	$0.044980	129,288.35	5,654,275	$0.003000	16,962.83
30	Winter Off-peak kWh	11,361,383	$0.028356	322,163.38	11,056,522	$0.000500	5,528.26
31	**Subtotal Delivery (Margin) Revenue**			**$1,644,561.64**			**$1,153,849.13**
	Base Power						
32	Summer On-peak kWh	2,599,727	$0.056452	146,759.81	6,641,029	$0.050669	336,494.32
33	Summer Shoulder-peak	922,051	$0.056452	52,051.64	-	$0.00	-
34	Summer Off-peak kWh	13,913,940	$0.023952	333,266.68	8,319,627	$0.026679	221,959.33
35	Winter On-peak kWh	2,874,352	$0.039341	113,079.88	5,654,275	$0.032893	185,986.08
36	Winter Off-peak kWh	11,361,383	$0.019341	219,740.51	11,056,522	$0.027092	299,543.28
37	**TOTAL TOU LGS-85AF REVENUE**			**$2,509,460.16**			**$2,197,832.14**
38	TOTAL SALES	31,671,453			31,671,453		

TUCSON ELECTRIC POWER COJMPANY
TEST YEAR RATES VS. PROPOSED RATES AND REVENUES
TEST PERIOD ENDING DECEMBER 31, 2011

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
	LGS Time of Use LGS-85N Consolidated with LGS TOU 85						
1	Customer Charge	756	$371.88	$281,141.28	756	$950.00	$718,200.00
2	Summer On-Peak kW	159,325	$11.87	1,891,023.85	136,794	$14.55	1,990,350.48
3	Summer Off-peak kW	152,908	$8.24	1,259,813.12	131,265	$10.92	1,433,412.12
4	Winter On-Peak kW	141,095	$8.91	1,256,876.98	168,568	$11.59	1,953,701.06
5	Winter Off-peak kW	140,289	$6.42	900,376.82	161,933	$9.10	1,473,590.00
6	Summer On-peak	14,680,576	$0.007500	110,104.32	21,189,064	$0.008600	182,225.95
7	Summer Shoulder-peak	13,087,176	$0.005000	65,435.88		$0.00	-
8	Summer Off-peak	61,745,731	$0.002500	154,364.33	55,253,420	$0.006000	331,520.52
9	Winter On-peak kWh	23,409,799	$0.002500	58,524.50	32,576,235	$0.003000	97,728.70
10	Winter Off-peak kWh	57,377,182	$0.000000	-	61,281,744	$0.000500	30,640.87
11	**Subtotal Delivery (Margin) Revenue**			**$5,977,661.07**			**$8,211,369.71**
	Base Power						
12	Summer On-peak kWh	14,680,576	$0.059253	869,868.15	21,189,064	$0.050669	1,073,628.70
13	Summer Shoulder-peak	13,087,176	$0.033588	439,572.05	-	$0.00	-
14	Summer Off-peak kWh	61,745,731	$0.025299	1,562,105.26	55,253,420	$0.026679	1,474,105.99
15	Winter On-peak kWh	23,409,799	$0.036088	844,812.82	32,576,235	$0.032893	1,071,530.09
16	Winter Off-peak kWh	57,377,182	$0.027799	1,595,028.28	61,281,744	$0.027092	1,660,245.02
17	TOTAL TOU LGS-85AN REVENUE			$11,289,047.63			$13,490,879.50
18	TOTAL SALES	170,300,463			170,300,463		

19	**SMALL GENERAL SERVICE STANDARD**	**$232,753,649.57**
20	**SMALL GENERAL SERVICE TIME OF USE**	**$13,948,269.99**
21	**GENERAL SERVICE MOBILE HOME PARKS**	**$6,174,143.90**
22	**WATER PUMPING SERVICE**	**$8,391,806.07**
23	**LARGE GENERAL SERVICE**	**$97,988,311.22**
24	**LARGE GENERAL SERVICE CONTRACT**	**$182,646.07**
25	**LARGE GENERAL SERVICE TIME OF USE**	**$16,748,009.97**
26	**GENERAL SERVICE COMMUNITY SOLAR**	**$38,883.97**
27	**GENERAL SERVICE (PS-40) TRANSITION ADJUSTMENT**	**($1,620,842.00)**
28	**GENERAL SERVICE TOTAL REVENUE**	**$374,604,878.75**

TUCSON ELECTRIC POWER COMPANY
TEST YEAR RATES VS. PROPOSED RATES AND REVENUES
TEST PERIOD ENDING DECEMBER 31, 2011

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
1	**LARGE LIGHT & POWER STANDARD SERVICE I-14**						
2	Customer Charge	48	$500.00	$24,000.00	48	$1,800.00	$86,400.00
3	Demand per kW	648,222	$19.02	12,331,770.68	657,888	$21.98	14,460,383.86
4	Summer kWh	194,411,279	$0.000433	84,180.08	164,577,383	$0.0032	526,647.63
5	Winter kWh	157,043,001	$0.000433	67,999.62	186,876,897	$0.0021	392,441.48
6	Power Factor Adjustment			(38,298.99)			-
7	**Subtotal Delivery (Margin) Revenue**			**$12,469,651.40**			**$15,465,872.97**
8	Base Power Summer	194,411,279	$0.032577	6,333,336.24	164,577,383	$0.031611	5,202,455.67
9	Base Power Winter	157,043,001	$0.025077	3,938,167.34	186,876,897	$0.028388	5,305,061.35
10	**TOTAL LL&P I-14 REVENUE**			**$22,741,154.98**			**$25,973,389.99**
11	TOTAL SALES	351,454,280			351,454,280		
12	**LLP Time of Use LLP-90F Consolidated with Rate LLP TOU I-90**				-		
13	Customer Charge	36	$500.00	$18,000.00	36	$2,000.00	$72,000.00
14	Summer On-Peak kW	129,214	$25.70	3,321,056.05	108,502	$20.49	2,223,204.65
15	Summer Shoulder-Peak kW	-	$19.45			$0.00	
16	Summer Off-peak kW	381	$13.20	5,026.79	0	$12.49	-
17	Winter On-Peak kW	118,244	$21.70	2,566,127.73	143,938	$15.49	2,229,604.52
18	Winter Off-peak kW	306	$9.20	2,817.33	0	$9.99	-
19	Summer On-peak	12,789,577	$0.000433	5,537.89	32,267,296	$0.006900	222,644.34
20	Summer Shoulder-peak	5,101,626	$0.000433	2,209.00		$0.00	-
21	Summer Off-peak	73,829,358	$0.000433	31,968.11	44,351,515	$0.006500	288,284.85
22	Winter On-peak kWh	15,295,174	$0.000433	6,622.81	30,752,002	$0.007500	230,640.02
23	Winter Off-peak kWh	63,468,318	$0.000433	27,481.78	63,113,261	$0.007100	448,104.16
24	Power Factor Adjustment Charge			(14,945.30)			-
25	**Subtotal Delivery (Margin) Revenue**			**$5,971,902.20**			**$5,714,482.53**
	Base Power						
26	Summer On-peak kWh	12,789,577	$0.052983	677,630.17	32,267,296	$0.045568	1,470,356.15
27	Summer Shoulder-peak	5,101,626	$0.052983	270,299.45	-	$0.00	-
28	Summer Off-peak kWh	73,829,358	$0.020483	1,512,246.74	44,351,515	$0.023985	1,063,771.09
29	Winter On-peak kWh	15,295,174	$0.035623	544,860.00	30,752,002	$0.029581	909,674.98
30	Winter Off-peak kWh	63,468,318	$0.015623	991,565.54	63,113,261	$0.024352	1,536,934.14
31	**TOTAL LLP-90F REVENUE**			**$9,968,504.09**			**$10,695,218.89**
32	TOTAL SALES	170,484,054			170,484,075		

TUCSON ELECTRIC POWER COJMPANY
TEST YEAR RATES VS. PROPOSED RATES AND REVENUES
TEST PERIOD ENDING DECEMBER 31, 2011

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
	LLP Time of Use LLP-90AF Consolidated with Rate LLP TOU I-90						
1	Customer Charge	12	$500.00	$6,000.00	12	$2,000.00	$24,000.00
2	Summer On-Peak kW	23,108	$25.58	591,115.52	19,420	$20.49	397,915.80
3	Summer Shoulder-Peak kW	0	$18.08	-	-	$0.00	-
4	Summer Off-peak kW	0	$10.58	-	-	$12.49	-
5	Winter On-Peak kW	21,095	$21.58	455,259.83	24,783	$15.49	383,888.67
6	Winter Off-peak kW	0	$10.58	-	-	$0.00	-
7	Summer On-peak	2,487,981	$0.006203	15,432.16	5,900,062	$0.006900	40,710.42
8	Summer Shoulder-peak	691,357	$0.006203	4,288.27	-	-	-
9	Summer Off-peak	12,031,280	$0.006203	74,626.22	8,805,988	$0.006500	57,238.92
10	Winter On-peak kWh	2,778,185	$0.006203	17,232.20	4,936,738	$0.007500	37,025.54
11	Winter Off-peak kWh	11,808,048	$0.006203	73,241.58	10,154,063	$0.007100	72,093.85
12	Power Factor Adjustment Charge			(991.62)			-
13	**Subtotal Delivery (Margin) Revenue**			**$1,236,204.14**			**$1,012,873.20**
	Base Power						
14	Summer On-peak kWh	2,487,981	$0.052983	131,820.68	5,900,062	$0.045568	268,854.00
15	Summer Shoulder-peak	691,357	$0.052983	36,630.18	-	$0.00	-
16	Summer Off-peak kWh	12,031,280	$0.020483	246,436.71	8,805,988	$0.023985	211,211.63
17	Winter On-peak kWh	2,778,185	$0.035623	98,967.27	4,936,738	$0.029581	146,033.65
18	Winter Off-peak kWh	11,808,048	$0.015623	184,477.14	10,154,063	$0.024352	247,271.74
19	**TOTAL LLP-90AF REVENUE**			**$1,934,536.13**			**$1,886,244.24**
20	TOTAL SALES	29,796,851			29,796,851		
21	**LLP Time of Use LLP-90AN Consolidated with Rate LLP TOU I-90**						
22	Customer Charge	72	$500.00	$24,000.00	72	$2,000.00	$144,000.00
23	Summer On-Peak kW	1,126,518	$20.03	5,631,073.96	942,458	$20.49	19,310,956.22
24	Summer Off-peak kW	0	$10.03	-	-	$12.49	-
25	Winter On-Peak kW	1,101,530	$15.03	3,830,620.95	1,293,879	$15.49	20,042,187.50
26	Winter Off-peak kW	0	$7.53	-	-	$9.99	-
27	Summer On-peak	119,764,712	$0.001113	31,295.27	259,407,650	$0.006900	1,789,912.78
28	Summer Shoulder-peak	117,575,158	$0.001113	29,824.13		$0.00	-
29	Summer Off-peak	482,023,611	$0.000716	80,888.09	320,205,034	$0.006500	2,081,332.72
30	Winter On-peak kWh	220,927,188	$0.000723	32,384.33	267,092,274	$0.007500	2,003,192.06
31	Winter Off-peak kWh	455,386,868	$0.000521	52,062.61	548,972,579	$0.007100	3,897,705.31
32	Power Factor Adjustment Charge			(9,596.13)			-
33	**Subtotal Delivery (Margin) Revenue**			**$9,702,553.21**			**$49,269,286.60**
	Base Power						
34	Summer On-peak kWh	119,764,712	$0.041786	1,174,936.52	259,407,650	$0.045568	11,820,687.78
35	Summer Shoulder-peak	117,575,158	$0.041786	1,119,704.50	0	$0.00	-
36	Summer Off-peak kWh	482,023,611	$0.026872	3,035,788.59	320,205,034	$0.023985	7,680,117.73
37	Winter On-peak kWh	220,927,188	$0.027126	1,215,016.88	267,092,274	$0.029581	7,900,856.57
38	Winter Off-peak kWh	455,386,868	$0.019542	1,952,797.64	548,972,579	$0.024352	13,368,580.25
39	**TOTAL LLP-90AN REVENUE**			**$18,200,797.34**			**$90,039,528.93**
40	TOTAL SALES	1,395,677,537			1,395,677,537		
41	**LARGE LIGHT & POWER STANDARD**						**$25,973,390**
42	**LARGE LIGHT & POWER TIME OF USE**						**102,620,992**
43	**LARGE LIGHT & POWER CONTRACT**						**1,680,035**
44	**LARGE LIGHT & POWER SERVICE TOTAL REVENUE**						**$130,274,417**

TUCSON ELECTRIC POWER COMPANY
TEST YEAR RATES VS. PROPOSED RATES AND REVENUES
TEST PERIOD ENDING DECEMBER 31, 2011

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue		Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
	Traffic Signal and Street Light Service PS-41							
1	Customer Charge	15,006	$0.00	$0.00		15,006	$0.00	$0.00
2	Summer kWh	11,178,373	$0.045580	509,510.24		11,178,373	$0.047600	532,090.55
3	Winter kWh	18,556,213	$0.045580	845,792.19		18,556,213	$0.047600	883,275.74
4	**Subtotal Delivery (Margin) Revenue**			$1,355,302.43				$1,415,366.29
5								
6	PPFAC SUMMER	11,178,373	$0.025817	288,592.06		11,178,373	$0.035111	392,483.85
7	PPFAC WINTER	18,556,213	$0.025817	479,065.75		18,556,213	$0.031532	585,114.51
8	**TOTAL PS-41 REVENUE**			$2,122,960.24				$2,392,964.66
9	P-41 Total Sales	29,734,586				29,734,586		
	Lighting Service P-50							
10	55Watt	1,428	$7.39	$10,552.92			$8.19	$11,695.32
11	70Watt	2,472	$7.39	18,268.08			$8.19	20,245.68
12	100 Watt	121,283	$7.39	896,281.37			$8.19	993,307.77
13	250 Watt	19,574	$11.09	217,114.81			$12.29	240,564.46
14	400 Watt	3,904	$17.11	66,797.44			$18.70	73,004.80
15	Underground Service	23,986	$14.01	336,139.80			$15.53	372,502.58
16	Pole	47,144	$2.58	121,725.81			$2.86	134,831.84
17	**Subtotal Delivery (Margin) Revenue**			$1,666,880.23				$1,846,152.45
18	**Base Powr**							
19	55Watt	1,428	$0.43	$609.76				
20	70Watt	2,472	$0.54	1,342.30				
21	100 Watt	121,283	$0.78	94,115.61	Base Power			
22	250 Watt	19,574	$1.94	37,973.56	Sum kWh	2,832,315	$0.035111	99,445.42
23	400 Watt	3,904	$3.10	12,118.02	Win kWh	4,863,888	$0.031532	153,368.11
24	**TOTAL LIGHTING SERVICE REVENUE**			$1,813,039.47				$2,098,965.99
25	**LIGHTING SERVICE TOTAL REVENUE**							$4,491,930.64
26	**TOTAL REVENUE REQUIREMENT ALL CLASSES**							$921,195,757

UNBUNDLED TARIFFS

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 101
Superseding:

Residential Electric Service (R-01)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

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.

For those dwellings and apartments where electric service has historically been measured through two meters, when one of the meters was installed pursuant to the Residential Electric Water Heating Service Rate (R-02F) which is no longer in effect, the electric service measured by such meters shall be combined for billing purposes.

Not applicable to resale, breakdown, temporary, 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
The service shall be single- or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE-SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge of Delivery Services:
Standard

Customer Charge, Single Phase service and minimum bill	$10.00 per month
Customer Charge, Three Phase service and minimum bill	$15.00 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option

Customer Charge, Single Phase with usage less than 2,000 kWh	$12.50 per month
Customer Charge, Three Phase with usage less than 2,000 kWh	$17.50 per month
Customer Charge, Single Phase with usage of 2,000 kWh or more	$16.50 per month
Customer Charge, Three Phase with usage of 2,000 kWh or more	$21.50 per month

Energy Charges ($/kWh)

Summer (May – September)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
0 – 500 kWh	$0.056200	$0.035111	*varies*	$0.091311
501 – 1,000 kWh	$0.067200	$0.035111	*varies*	$0.102311
1,001 – 3,500 kWh	$0.079800	$0.035111	*varies*	$0.114911
Over 3,500 kWh	$0.088200	$0.035111	*varies*	$0.123311

Filed By:	Kentton C. Grant	Rate:	R-01
Title:	Vice President of Finance and Rates	Effective:	Pending
District:	Entire Electric Service Area	Decision No.:	

DECISION NO. 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 101-1
Superseding:

Winter (October - April)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
0 – 500 kWh	$0.056200	$0.031532	*varies*	$0.087732
501 – 1,000 kWh	$0.065200	$0.031532	*varies*	$0.096732
1,001 – 3,500 kWh	$0.078100	$0.031532	*varies*	$0.109632
Over 3,000 kWh	$0.087100	$0.031532	*varies*	$0.118632

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY LIFELINE DISCOUNT:
This discount is only available to new and eligible Lifeline Customers whose monthly bill shall be in accordance to the rate above except that a discount of $9.00 per month shall be applied. No Lifeline discount will be applied that will reduce the volumetric charges to less than zero.

LIFELINE ELIGIBILITY
1. The TEP account must be in the customer's name applying for a lifeline discount.
2. Applicant must be a TEP residential customer residing at the premise.
3. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on TEP's website at www.tep.com or contact a TEP customer care representative.

LOST FIXED COST RECOVERY (LFCR) – RIDER 8
For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

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

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 101-2
Superseding:

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

AUTOMATED METER OPT-OUT
Residential rate class Customers may request, and have installed, meters that do not transmit data wirelessly. A one-time *automated meter opt-out change-out fee*, as specified in TEP's Statement of Charges, will apply for the installation of each analog meter that replaces a meter currently in service at the customer's premises that transmits data wirelessly. For a Customer choosing the Automated Meter Opt-out, an additional monthly customer charge as specified in the TEP Statement of Charges will be added to the applicable Customer Charge for as long as the analog meter is left in service.

The Customer may choose to self-read the analog meter. The terms and conditions for self reading of the meter shall be in accordance with Section 10 of the TEP Rules and Regulations.

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 rate.

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.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Standard		
Description	**Single Phase**	**Three Phase**
Meter Services	$1.74 per month	$2.60 per month
Meter Reading	$1.17 per month	$1.77 per month
Billing & Collection	$5.04 per month	$7.56 per month
Customer Delivery	$2.05 per month	$3.07 per month
Total	**$10.00 per month**	**$15.00 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh		
Description	**Single Phase**	**Three Phase**
Meter Services	$1.74 per month	$2.60 per month
Meter Reading	$1.17 per month	$1.77 per month
Billing & Collection	$5.04 per month	$7.56 per month
Customer Delivery	$2.05 per month	$3.07 per month
LFCR	$2.50 per month	$2.50 per month
Total	**$12.50 per month**	**$17.50 per month**

Filed By:	Kentton C. Grant	Rate:	R-01
Title:	Vice President of Finance and Rates	Effective:	Pending
District:	Entire Electric Service Area	Decision No.:	

DECISION NO. 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 101-3
Superseding:

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more		
Description	**Single Phase**	**Three Phase**
Meter Services	$1.74 per month	$2.60 per month
Meter Reading	$1.17 per month	$1.77 per month
Billing & Collection	$5.04 per month	$7.56 per month
Customer Delivery	$2.05 per month	$3.07 per month
LFCR	$6.50 per month	$6.50 per month
Total	**$16.50 per month**	**$21.50 per month**

Energy Charge Components (Unbundled):

Component	Summer (May – September)	Winter (October - April)
0 – 500 kWh	$0.001800	$0.004200
501 – 1,000 kWh	$0.012800	$0.013200
1,001 – 3,500 kWh	$0.025400	$0.026100
Over 3,500 kWh	$0.033800	$0.035100
Generation Capacity	$0.039800	$0.037400
Fixed Must Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charges:

	Summer (May – September)	Winter (October - April)
Base Power Component	$0.03511100	$0.03153200
PPFAC	In accordance with Rider 1 - PPFAC	

Filed By: Kentton C. Grant
Title: Vice President of Finance and Rates
District: Entire Electric Service Area

Rate: R-01
Effective: Pending
Decision No.:

DECISION NO. 73912

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 102
Superseding:

Residential Time-of-Use (R-80)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all single 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.

Not applicable to resale, breakdown, temporary, standby, 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 this rate for a minimum period of one (1) year.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charges:

Standard
Customer Charge, Single Phase service and minimum bill — $11.50 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option
Customer Charge, Single Phase with usage less than 2,000 kWh — $14.00 per month
Customer Charge, Single Phase with usage of 2,000 kWh or more — $18.00 per month

Energy Charges ($/kWh):

Summer (May – September)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC	Total[3]
On-Peak	$0.066800	$0.050669	*varies*	$0.117469
Off-Peak	$0.051800	$0.026679	*varies*	$0.078479

Winter (October – April)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC	Total[3]
On-Peak	$0.056800	$0.032893	*varies*	$0.089693
Off-Peak	$0.041800	$0.027092	*varies*	$0.068892

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 102-1
Superseding:

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY LIFELINE DISCOUNT:
This discount is only available to new and eligible Lifeline customers whose monthly bill shall be in accordance to the rate above except that a discount of $9.00 per month shall be applied. No Lifeline discount will be applied that will reduce the volumetric charges to less than zero.

TIME-OF-USE TIME PERIODS
The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

ELECTRIC VEHICLES
Customers who own and operate Electric Vehicles will receive a 5% discount to the Base Fuel during the off-peak period and the PPFAC. Customers must provide documentation for highway approved Electric Vehicles.

LOST FIXED COST RECOVERY (LFCR) – RIDER 8
For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

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

Filed By:	Kentton C. Grant	Rate:	R-80
Title:	Vice President of Finance and Rates	Effective:	Pending
District:	Entire Electric Service Area	Decision No.:	

DECISION NO. 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 102-2
Superseding:

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of *Charges which is available on TEP's website at* www.tep.com.

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 rate.

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.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Standard	
Description	**Single Phase**
Meter Services	$2.00 per month
Meter Reading	$1.34 per month
Billing & Collection	$5.80 per month
Customer Delivery	$2.36 per month
Total	**$11.50 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh	
Description	**Single Phase**
Meter Services	$2.00 per month
Meter Reading	$1.34 per month
Billing & Collection	$5.80 per month
Customer Delivery	$2.36 per month
LFCR	$2.50 per month
Total	**$14.00 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more	
Description	**Single Phase**
Meter Services	$2.00 per month
Meter Reading	$1.34 per month
Billing & Collection	$5.80 per month
Customer Delivery	$2.36 per month
LFCR	$6.50 per month
Total	**$18.00 per month**

DECISION NO. 73912

Tucson Electric Power Company

Original Sheet No.: 102-3
Superseding:

TEP
Tucson Electric Power

Energy Charge Components (Unbundled):

Summer (May – September)	On-Peak	Off-Peak
Delivery-Energy	$0.011300	$0.011300
Generation Capacity	$0.040900	$0.025900
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge

Summer (May – September)	On-Peak	Off-Peak
Base Power Component	$0.05066900	$0.02667900
PPFAC	In accordance with Rider 1 - PPFAC	

Energy Charge Components (Unbundled):

Winter (October - April)	On-Peak	Off-Peak
Delivery-Energy	$0.011300	$0.011300
Generation Capacity	$0.030900	$0.015900
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge

Winter (October - April)	On-Peak	Off-Peak
Base Power Component	$0.03289300	$0.02709200
PPFAC	In accordance with Rider 1 - PPFAC	

Filed By: Kentton C. Grant
Title: Vice President of Finance and Rates
District: Entire Electric Service Area

Rate: R-80
Effective: Pending
Decision No.:

DECISION NO. 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 103
Superseding:

Residential Lifeline/Senior Discount (R-04-01F)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

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.

The discount is also available to tenants of master metered mobile home parks and apartments. The applicant must be 65 years of age, or older, and reside at the premise to qualify.

Not applicable to resale, breakdown, temporary, 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
The service shall be single-phase or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge of Delivery Services:
Standard
Customer Charge, Single Phase service and minimum bill — $ 6.90 per month
Customer Charge, Three Phase service and minimum bill — $11.90 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option
Customer Charge, Single Phase with usage less than 2,000 kWh — $ 9.40 per month
Customer Charge, Three Phase with usage less than 2,000 kWh — $14.40 per month

Customer Charge, Single Phase with usage of 2,000 kWh or more — $13.40 per month
Customer Charge, Three Phase with usage of 2,000 kWh or more — $18.40 per month

Energy Charges ($/kWh)

	Delivery Services-Energy[1]	Power Supply Charges[2]		Total[3]
		Base Power	PPFAC[2]	
Summer (May – September)	$0.0611	$0.033198	*varies*	$0.094298
Winter (October – April)	$0.0570	$0.025698	*varies*	$0.082698

Filed By:	Kentton C. Grant	Rate:	R-04-01F
Title:	Vice President of Finance and Rates	Effective:	Pending
District:	Entire Electric Service Area	Decision No.:	

DECISION NO. 73912

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY DISCOUNT

The following monthly discount applies to the rate incorporated herein:

For Bills with Usage of:	Monthly Discount will be applied to the total bill excluding the Customer Charge:
0 - 300 kWh	35%
301 - 600 kWh	30%
601- 1,000 kWh	25%
1001- 1,500 kWh	15%
Over 1,500 kWh	0%

LOST FIXED COST RECOVERY (LFCR) – RIDER 8

For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

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 (AZISA) CHARGE

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

TEP STATEMENT OF CHARGES

For all charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 103-2
Superseding:

AUTOMATED METER OPT-OUT

Residential rate class Customers may request, and have installed, meters that do not transmit data wirelessly. A one-time automated meter opt-out change-out fee, as specified in TEP's Statement of Charges, will apply for the installation of each analog meter that replaces a meter currently in service at the customer's premises that transmits data wirelessly. For a Customer choosing the Automated Meter Opt-out, an additional monthly customer charge as specified in the TEP Statement of Charges will be added to the applicable Customer Charge for as long as the analog meter is left in service.

The Customer may choose to self-read the analog meter. The terms and conditions for self reading of the meter shall be in accordance with Section 10 of the TEP Rules and Regulations.

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 rate.

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.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Standard		
Description	**Single Phase**	**Three Phase**
Meter Services	$1.20 per month	$2.07 per month
Meter Reading	$0.81 per month	$1.39 per month
Billing & Collection	$3.48 per month	$6.00 per month
Customer Delivery	$1.41 per month	$2.44 per month
Total	**$6.90 per month**	**$11.90 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh		
Description	**Single Phase**	**Three Phase**
Meter Services	$1.20 per month	$2.07 per month
Meter Reading	$0.81 per month	$1.39 per month
Billing & Collection	$3.48 per month	$6.00 per month
Customer Delivery	$1.41 per month	$2.44 per month
LFCR	$2.50 per month	$2.50 per month
Total	**$9.40 per month**	**$14.40 per month**

Filed By: Kentton C. Grant
Title: Vice President of Finance and Rates
District: Entire Electric Service Area

Rate: R-04-01F
Effective: Pending
Decision No.:

DECISION NO. 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 103-3
Superseding:

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more		
Description	**Single Phase**	**Three Phase**
Meter Services	$1.20 per month	$2.07 per month
Meter Reading	$0.81 per month	$1.39 per month
Billing & Collection	$3.48 per month	$6.00 per month
Customer Delivery	$1.41 per month	$2.44 per month
LFCR	$6.50 per month	$6.50 per month
Total	**$13.40 per month**	**$18.40 per month**

Energy Charge Components of Delivery Services (Unbundled):

Component	Summer (May – September)	Winter (October - April)
Local Delivery-Energy	$0.013800	$0.011300
Generation Capacity	$0.032700	$0.031100
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge:

	Summer (May – September)	Winter (October - April)
Base Power Component	$0.033198	$0.025698
PPFAC	In accordance with Rider 1 - PPFAC	

Filed By: Kentton C. Grant
Title: Vice President of Finance and Rates
District: Entire Electric Service Area

Rate: R-04-01F
Effective: Pending
Decision No.:

DECISION NO. 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 104
Superseding:

Residential Lifeline/Senior Discount (R-04-21F)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

APPLICABILITY
To all single-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.

The discount is also available to tenants of master metered mobile home parks and apartments. The applicant must be 65 years of age, or older, and reside at the premise to qualify.

Not applicable to resale, breakdown, temporary, 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
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charges:
Standard
Customer Charge, Single Phase service and minimum bill $ 8.86 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option
Customer Charge, Single Phase with usage less than 2,000 kWh $11.36 per month
Customer Charge, Single Phase with usage of 2,000 kWh or more $15.36 per month

Energy Charges ($/kWh):

Summer (May – September)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC	Total[3]
On-Peak	$0.0788	$0.053198	*varies*	$0.131998
Off-Peak	$0.0301	$0.023198	*varies*	$0.053298

Winter (October – April)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC	Total[3]
On-Peak	$0.0652	$0.040698	*varies*	$0.105898
Off-Peak	$0.0330	$0.020698	*varies*	$0.053698

Filed By:	Kentton C. Grant	Rate:	R-04-21F
Title:	Vice President of Finance and Rates	Effective:	Pending
District:	Entire Electric Service Area	Decision No.:	

DECISION NO. 73912

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.
2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.
3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY DISCOUNT

The following monthly discount applies to the rate incorporated herein:

For Bills with Usage of:	Monthly Discount will be applied to the total bill excluding the Customer Charge:
0 - 300 kWh	35%
301 - 600 kWh	30%
601 - 1000 kWh	25%
1001 - 1500 kWh	15%
Over 1500 kWh	0%

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 10:00 a.m. to 10:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

LOST FIXED COST RECOVERY (LFCR) – RIDER 8

For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

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 (AZISA) CHARGE

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

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 104-2
Superseding:

TEP STATEMENT OF CHARGES
For all charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

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 rate.

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.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Standard	
Description	**Single Phase**
Meter Services	$1.54 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.47 per month
Customer Delivery	$1.82 per month
Total	**$8.86 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh	
Description	**Single Phase**
Meter Services	$1.54 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.47 per month
Customer Delivery	$1.82 per month
LFCR	$2.50 per month
Total	**$11.36 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option – usage of 2,000 kWh or more	
Description	**Single Phase**
Meter Services	$1.54 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.47 per month
Customer Delivery	$1.82 per month
LFCR	$6.50 per month
Total	**$15.36 per month**

Docket No. E-01933A-12-0291

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 104-3
Superseding:

Energy Charge Components of Delivery Services (Unbundled):

Summer (May – September)	On-Peak	Off-Peak
Local Delivery-Energy	$0.011300	$0.011300
Generation Capacity	$0.052900	$0.004200
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge

Summer (May – September)	On-Peak	Off-Peak
Base Power Component	$0.05319800	$0.02319800
PPFAC	In accordance with Rider 1 - PPFAC	

Energy Charge Components of Delivery Services (Unbundled):

Winter (October – April)	On-Peak	Off-Peak
Local Delivery-Energy	$0.011300	$0.011300
Generation Capacity	$0.039300	$0.007100
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge

Winter (October – April)	On-Peak	Off-Peak
Base Power Component	$0.04069800	$0.02069800
PPFAC	In accordance with Rider 1 - PPFAC	

DECISION NO. 73912

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 105
Superseding:

Residential Lifeline/Senior Discount (R-04-70F)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

APPLICABILITY
To all single-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.

The discount is also available to tenants of master metered mobile home parks and apartments. The applicant must be 65 years of age, or older, and reside at the premise to qualify.

Not applicable to resale, breakdown, temporary, 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
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charges:
Standard
Customer Charge, Single Phase service and minimum bill — $ 8.78 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option
Customer Charge, Single Phase with usage less than 2,000 kWh — $11.28 per month
Customer Charge, Single Phase with usage of 2,000 kWh or more — $15.28 per month

Energy Charges ($/kWh):

Summer (May – September)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC	Total[3]
On-Peak	$0.139300	$0.055698	*varies*	$0.194998
Shoulder	$0.074000	$0.048198	*varies*	$0.122198
Off-Peak	$0.037900	$0.023198	*varies*	$0.061098

Winter (October – April)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC	Total[3]
On-Peak	$0.092500	$0.040698	*varies*	$0.133198
Off-Peak	$0.024900	$0.020698	*varies*	$0.045598

DECISION NO. 73912

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.
2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.
3. *Total is calculated above for illustrative purposes* (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY DISCOUNT

The following monthly discount applies to the rate incorporated herein:

For Bills with Usage of:	Monthly Discount will be applied to the total bill excluding the Customer Charge:
0- 300 kWh	35%
301- 600 kWh	30%
601- 1,000 kWh	25%
1001- 1,500 kWh	15%
Over 1,500 kWh	0%

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 1:00 p.m. to 6:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The summer Shoulder period is 6:00 p.m. to 8:00 p.m. Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

LOST FIXED COST RECOVERY (LFCR) – RIDER 8

For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

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 (AZISA) CHARGE

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

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 105-2
Superseding:

TEP STATEMENT OF CHARGES
For all charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

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 rate.

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.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Standard	
Description	**Single Phase**
Meter Services	$1.52 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.43 per month
Customer Delivery	$1.80 per month
Total	**$8.78 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh	
Description	**Single Phase**
Meter Services	$1.52 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.43 per month
Customer Delivery	$1.80 per month
LFCR	$2.50 per month
Total	**$11.28 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more	
Description	**Single Phase**
Meter Services	$1.52 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.43 per month
Customer Delivery	$1.80 per month
LFCR	$6.50 per month
Total	**$15.28 per month**

DECISION NO. 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 105-3
Superseding:

Energy Charge Components of Delivery Services (Unbundled):

Summer (May – September)	On-Peak	Shoulder-Peak	Off-Peak
Local Delivery-Energy	$0.011300	$0.011300	$0.011300
Generation Capacity	$0.113400	$0.048100	$0.012000
Fixed Must-Run	$0.003000	$0.003000	$0.003000
Transmission	$0.009000	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:			
System Control & Dispatch	$0.000100	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT			

Power Supply Charge

Summer (May – September)	On-Peak	Shoulder-Peak	Off-Peak
Base Power Component	$0.055698	$0.048198	$0.023198
PPFAC	In accordance with Rider 1 – PPFAC		

Energy Charge Components of Delivery Services (Unbundled):

Winter (October – April)	On-Peak	Off-Peak
Local Delivery-Energy	$0.010200	$0.010200
Generation Capacity	$0.067700	$0.000100
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge

Winter (October – April)	On-Peak	Off-Peak
Base Power Component	$0.040698	$0.020698
PPFAC	In accordance with Rider 1 - PPFAC	

Filed By: Kentton C. Grant
Title: Vice President of Finance and Rates
District: Entire Electric Service Area

Rate: R-04-70F
Effective: Pending
Decision No.:

DECISION NO. 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 106
Superseding:

Residential Lifeline Discount (R-05-01F)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

APPLICABILITY
To all single-phase and 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.

The discount is also available to tenants of master metered mobile home parks and apartments.

Not applicable to resale, breakdown, temporary, 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
The service shall be single-phase and three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

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

BUNDLED STANDARD OFFER SERVICE-SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge of Delivery Services:
Standard
Customer Charge, Single Phase service and minimum bill $ 6.90 per month
Customer Charge, Three Phase service and minimum bill $11.90 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option
Customer Charge, Single Phase with usage less than 2,000 kWh $ 9.40 per month
Customer Charge, Three Phase with usage less than 2,000 kWh $14.40 per month

Customer Charge, Single Phase with usage of 2,000 kWh or more $13.40 per month
Customer Charge, Three Phase with usage of 2,000 kWh or more $18.40 per month

Energy Charges ($/kWh)

	Delivery Services-Energy[1]	Power Supply Charges[2]		
		Base Power	PPFAC[2]	Total[3]
Summer (May – September)	$0.061100	$0.033198	varies	$0.094298
Winter (October – April)	$0.057000	$0.025698	varies	$0.082698

DECISION NO. 73912

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY DISCOUNT

The following monthly discount applies to the rate incorporated herein:

For Bills with Usage of:	Monthly Discount will be applied to the total bill excluding the Customer Charge:
0- 300 kWh	25%
301- 600 kWh	20%
601- 1,000 kWh	15%
Over 1,000 kWh	0%

LOST FIXED COST RECOVERY (LFCR) – RIDER 8

For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

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 (AZISA) CHARGE

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

TEP STATEMENT OF CHARGES

For all charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 106-2
Superseding:

AUTOMATED METER OPT-OUT
Residential rate class Customers may request, and have installed, meters that do not transmit data wirelessly. A one-time automated meter opt-out change-out fee, as specified in TEP's Statement of Charges, will apply for the installation of each analog meter that replaces a meter currently in service at the customer's premises that transmits data wirelessly. For a Customer choosing the Automated Meter Opt-out, an additional monthly customer charge as specified in the TEP Statement of Charges will be added to the applicable Customer Charge for as long as the analog meter is left in service.

The Customer may choose to self-read the analog meter. The terms and conditions for self reading of the meter shall be in accordance with Section 10 of the TEP Rules and Regulations.

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 rate.

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.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Standard		
Description	**Single Phase**	**Three Phase**
Meter Services	$1.20 per month	$2.07 per month
Meter Reading	$0.81 per month	$1.39 per month
Billing & Collection	$3.48 per month	$6.00 per month
Customer Delivery	$1.41 per month	$2.44 per month
Total	**$6.90 per month**	**$11.90 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh		
Description	**Single Phase**	**Three Phase**
Meter Services	$1.20 per month	$2.07 per month
Meter Reading	$0.81 per month	$1.39 per month
Billing & Collection	$3.48 per month	$6.00 per month
Customer Delivery	$1.41 per month	$2.44 per month
LFCR	$2.50 per month	$2.50 per month
Total	**$9.40 per month**	**$14.40 per month**

DECISION NO. 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 106-3
Superseding:

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more		
Description	**Single Phase**	**Three Phase**
Meter Services	$1.20 per month	$2.07 per month
Meter Reading	$0.81 per month	$1.39 per month
Billing & Collection	$3.48 per month	$6.00 per month
Customer Delivery	$1.41 per month	$2.44 per month
LFCR	$6.50 per month	$6.50 per month
Total	**$13.40 per month**	**$18.40 per month**

Energy Charge Components of Delivery Services (Unbundled):

Component	Summer (May – September)	Winter (October - April)
Local Delivery-Energy	$0.013800	$0.011300
Generation Capacity	$0.032700	$0.031100
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge:

	Summer (May – September)	Winter (October - April)
Base Power Component	$0.033198	$0.025698
PPFAC	In accordance with Rider 1 - PPFAC	

Filed By: Kentton C. Grant
Title: Vice President of Finance and Rates
District: Entire Electric Service Area

Rate: R-05-01F
Effective: Pending
Decision No.:

DECISION NO. 73912

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 107
Superseding:

Residential Lifeline Discount (R-05-21F)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

APPLICABILITY
To all single-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.

The discount is also available to tenants of master metered mobile home parks and apartments. The applicant must reside at the premise to qualify.

Not applicable to resale, breakdown, temporary, 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
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charges:
Standard
Customer Charge, Single Phase service and minimum bill — $ 8.86 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option
Customer Charge, Single Phase with usage less than 2,000 kWh — $11.36 per month
Customer Charge, Single Phase with usage of 2,000 kWh or more — $15.36 per month

Energy Charges ($/kWh):

Summer (May – September)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC	Total[3]
On-Peak	$0.078800	$0.053198	*varies*	$0.131998
Off-Peak	$0.030100	$0.023198	*varies*	$0.053298

Winter (October – April)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC	Total[3]
On-Peak	$0.065200	$0.040698	*varies*	$0.105898
Off-Peak	$0.033000	$0.020698	*varies*	$0.053698

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 107-1
Superseding:

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

3. *Total is calculated above for illustrative purposes* (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY DISCOUNT
The following monthly discount applies to the rate incorporated herein:

For Bills with Usage of:	Monthly Discount will be applied to the total bill excluding the Customer Charge:
0 - 300 kWh	25%
301 - 600 kWh	20%
601 - 1000 kWh	15%
Over 1000 kWh	0%

TIME-OF-USE TIME PERIODS
The Summer On-Peak period is 10:00 a.m. to 10:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

LOST FIXED COST RECOVERY (LFCR) – RIDER 8
For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

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

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 107-2
Superseding:

TEP STATEMENT OF CHARGES
For all charges and assessments approved by the Arizona Corporation Commission see the Statement of Charges which is available on TEP's website at www.tep.com.

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 rate.

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.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Standard	
Description	**Single Phase**
Meter Services	$1.54 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.47 per month
Customer Delivery	$1.82 per month
Total	**$8.86 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh	
Description	**Single Phase**
Meter Services	$1.54 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.47 per month
Customer Delivery	$1.82 per month
LFCR	$2.50 per month
Total	**$11.36 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more	
Description	**Single Phase**
Meter Services	$1.54 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.47 per month
Customer Delivery	$1.82 per month
LFCR	$6.50 per month
Total	**$15.36 per month**

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 107-3
Superseding:

Energy Components of Delivery Services (Unbundled):

Summer (May – September)	On-Peak	Off-Peak
Local Delivery-Energy	$0.011300	$0.011300
Generation Capacity	$0.052900	$0.004200
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge

Summer (May – September)	On-Peak	Off-Peak
Base Power Component	$0.053198	$0.023198
PPFAC	In accordance with Rider 1 - PPFAC	

Energy Charge Components of Delivery Services (Unbundled):

Winter (October – April)	On-Peak	Off-Peak
Local Delivery-Energy	$0.011300	$0.011300
Generation Capacity	$0.039300	$0.007100
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge

Winter (October – April)	On-Peak	Off-Peak
Base Power Component	$0.040698	$0.020698
PPFAC	In accordance with Rider 1 - PPFAC	

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 108
Superseding:

Residential Lifeline Discount (R-05-70F)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

APPLICABILITY
To all single-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.

The discount is also available to tenants of master metered mobile home parks and apartments. The applicant must reside at the premise to qualify.

Not applicable to resale, breakdown, temporary, 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
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charges:
Standard
Customer Charge, Single Phase service and minimum bill $ 8.78 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option
Customer Charge, Single Phase with usage less than 2,000 kWh $11.28 per month
Customer Charge, Single Phase with usage of 2,000 kWh or more $15.28 per month

Energy Charges ($/kWh):

Summer (May – September)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC	Total[3]
On-Peak	$0.139300	$0.055698	*varies*	$0.194998
Shoulder	$0.074000	$0.048198	*varies*	$0.122198
Off-Peak	$0.037900	$0.023198	*varies*	$0.061098

Winter (October – April)	Delivery Services-Energy[1]	Power Supply Charges2 Base Power	PPFAC	Total[3]
On-Peak	$0.092500	$0.040698	*varies*	$0.133198
Off-Peak	$0.024900	$0.020698	*varies*	$0.045598

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 108-1
Superseding:

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.
2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.
3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY DISCOUNT

The following monthly discount applies to the rate incorporated herein:

For Bills with Usage of:	Monthly Discount will be applied to the total bill excluding the Customer Charge:
0-300 kWh	25%
301-600 kWh	20%
601-1,000 kWh	15%
Over 1,000 kWh	0%

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 1:00 p.m. to 6:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The summer Shoulder period is 6:00 p.m. to 8:00 p.m. Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

LOST FIXED COST RECOVERY (LFCR) – RIDER 8

For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

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 (AZISA) CHARGE

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

DECISION NO. 73912

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 108-2
Superseding:

TEP STATEMENT OF CHARGES
For all charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

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 rate.

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.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Standard	
Description	**Single Phase**
Meter Services	$1.52 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.43 per month
Customer Delivery	$1.80 per month
Total	**$8.78 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh	
Description	**Single Phase**
Meter Services	$1.52 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.43 per month
Customer Delivery	$1.80 per month
LFCR	$2.50 per month
Total	**$11.28 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option – usage of 2,000 kWh or more	
Description	**Single Phase**
Meter Services	$1.52 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.43 per month
Customer Delivery	$1.80 per month
LFCR	$6.50 per month
Total	**$15.28 per month**

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 108-3
Superseding:

Energy Charge Components of Delivery Services (Unbundled):

Summer (May – September)	On-Peak	Shoulder-Peak	Off-Peak
Local Delivery-Energy	$0.011300	$0.011300	$0.011300
Generation Capacity	$0.113400	$0.048100	$0.012000
Fixed Must-Run	$0.003000	$0.003000	$0.003000
Transmission	$0.009000	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:			
System Control & Dispatch	$0.000100	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT			

Power Supply Charge

Summer (May – September)	On-Peak	Shoulder-Peak	Off-Peak
Base Power Component	$0.055698	$0.048198	$0.023198
PPFAC	In accordance with Rider 1 - PPFAC		

Energy Charge Components of Delivery Services (Unbundled):

Winter (October – April)	On-Peak	Off-Peak
Local Delivery-Energy	$0.010200	$0.010200
Generation Capacity	$0.067700	$0.000100
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge

Winter (October – April)	On-Peak	Off-Peak
Base Power Component	$0.040698	$0.020698
PPFAC	In accordance with Rider 1 - PPFAC	

Filed By:	Kentton C. Grant	Rate:	R-05-70F
Title:	Vice President of Finance and Rates	Effective:	Pending
District:	*Entire Electric Service Area*	Decision No.:	

DECISION NO. 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 109
Superseding:

Residential Lifeline Discount (R-05-201AF)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

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 rate 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 rate. Not with standing the above, the customer's use of solar energy for any purpose shall not preclude subscription to this rate.

The discount is also available to tenants of master metered mobile home parks and apartments.

Not applicable to resale, breakdown, temporary, 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
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE-SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge of Delivery Services:
Standard
Customer Charge, Single Phase service and minimum bill — $ 6.90 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option
Customer Charge, Single Phase with usage less than 2,000 kWh — $ 9.40 per month

Customer Charge, Single Phase with usage of 2,000 kWh or more — $13.40 per month

Energy Charges ($/kWh)

	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
Mid-Summer (June – August)	$0.0611	$0.033198	*varies*	$0.094298
Remaining-summer (May & September)	$0.0436	$0.033198	*varies*	$0.076798
Winter (October – April)	$0.0413	$0.027198	*varies*	$0.068498

DECISION NO. 73912

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY DISCOUNT
The following monthly discount applies to the rate incorporated herein:

For Bills with Usage of:	Monthly Discount will be applied to the total bill excluding the Customer Charge:
0 - 300 kWh	25%
301 - 600 kWh	20%
601 - 1000 kWh	15%
Over 1000 kWh	0%

LOST FIXED COST RECOVERY (LFCR) – RIDER 8
For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

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

TEP STATEMENT OF CHARGES
For all charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

AUTOMATED METER OPT-OUT

Residential rate class Customers may request, and have installed, meters that do not transmit data wirelessly. A one-time automated meter opt-out change-out fee, as specified in TEP's Statement of Charges, will apply for the installation of each analog meter that replaces a meter currently in service at the customer's premises that transmits data wirelessly. For a Customer choosing the Automated Meter Opt-out, an additional monthly customer charge as specified in the TEP Statement of Charges will be added to the applicable Customer Charge for as long as the analog meter is left in service.

The Customer may choose to self-read the analog meter. The terms and conditions for self reading of the meter shall be in accordance with Section 10 of the TEP Rules and Regulations.

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 rate.

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.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

	Standard
Description	**Single Phase**
Meter Services	$1.20 per month
Meter Reading	$0.81 per month
Billing & Collection	$3.48 per month
Customer Delivery	$1.41 per month
Total	**$6.90 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh	
Description	**Single Phase**
Meter Services	$1.20 per month
Meter Reading	$0.81 per month
Billing & Collection	$3.48 per month
Customer Delivery	$1.41 per month
LFCR	$2.50 per month
Total	**$9.40 per month**

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 109-3
Superseding:

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more	
Description	**Single Phase**
Meter Services	$1.20 per month
Meter Reading	$0.81 per month
Billing & Collection	$3.48 per month
Customer Delivery	$1.41 per month
LFCR	$6.50 per month
Total	**$13.40 per month**

Energy Charge Components of Delivery Services (Unbundled):

Component	Mid Summer (June -August)	Remaining Summer (May & September)	Winter (October – April)
Local Delivery-Energy	$0.020600	$0.003100	$0.006800
Generation Capacity	$0.025900	$0.025900	$0.019900
Fixed Must-Run	$0.003000	$0.003000	$0.003000
Transmission	$0.009000	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:			
System Control & Dispatch	$0.000100	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT			

Power Supply Charge:

	Mid Summer (June -August)	Remaining Summer (May & September)	Winter (October – April)
Base Power Component	$0.033198	$0.033198	$0.027198
PPFAC	In accordance with Rider 1 - PPFAC		

Filed By: Kentton C. Grant
Title: Vice President of Finance and Rates
District: Entire Electric Service Area

Rate: R-05-201AF
Effective: Pending
Decision No.:

DECISION NO. 73912

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 110
Superseding:

Residential Lifeline Discount (R-06-01F)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

APPLICABILITY
To all single-phase and 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.

The discount is also available to tenants of master metered mobile home parks and apartments.

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

ELIGIBILITY
1. The TEP account must be in the customer's name applying for a lifeline discount.
2. Applicant must be a TEP residential customer residing at the premise.
3. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on TEP's website at www.tep.com or contact a TEP customer care representative.

CHARACTER OF SERVICE
The service shall be single-phase or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE-SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge of Delivery Services:
Standard

Customer Charge, Single Phase service and minimum bill	$ 6.90 per month
Customer Charge, Three Phase service and minimum bill	$11.90 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option

Customer Charge, Single Phase with usage less than 2,000 kWh	$ 9.40 per month
Customer Charge, Three Phase with usage less than 2,000 kWh	$14.40 per month
Customer Charge, Single Phase with usage of 2,000 kWh or more	$13.40 per month
Customer Charge, Three Phase with usage of 2,000 kWh or more	$18.40 per month

Energy Charges ($/kWh)

	Delivery Services-Energy[1]	Power Supply Charges[2]		
		Base Power	PPFAC[2]	Total[3]
Summer (May – September)	$0.061100	$0.033198	varies	$0.094298
Winter (October – April)	$0.057000	$0.025698	varies	$0.082698

Filed By:	Kentton C. Grant	Rate:	R-06-01F
Title:	Vice President of Finance and Rates	Effective:	Pending
District:	Entire Electric Service Area	Decision No.:	

DECISION NO. 73912

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY DISCOUNT:
The monthly bill shall be in accordance to the rate above except that a discount up to $9.00 per month shall be applied to Delivery Services-Energy and Power Supply Charges. No Lifeline discount will be applied that will reduce the volumetric charges to less than zero.

LOST FIXED COST RECOVERY (LFCR) – RIDER 8
For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

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

TEP STATEMENT OF CHARGES
For all charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

AUTOMATED METER OPT-OUT
Residential rate class Customers may request, and have installed, meters that do not transmit data wirelessly. A one-time automated meter opt-out change-out fee, as specified in TEP's Statement of Charges, will apply for the installation of each analog meter that replaces a meter currently in service at the customer's premises that transmits data wirelessly. For a Customer choosing the Automated Meter Opt-out, an additional monthly customer charge as specified in the TEP Statement of Charges will be added to the applicable Customer Charge for as long as the analog meter is left in service.

The Customer may choose to self-read the analog meter. The terms and conditions for self reading of the meter shall be in accordance with Section 10 of the TEP Rules and Regulations.

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.

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 110-2
Superseding:

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 rate.

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.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Standard		
Description	**Single Phase**	**Three Phase**
Meter Services	$1.20 per month	$2.07 per month
Meter Reading	$0.81 per month	$1.39 per month
Billing & Collection	$3.48 per month	$6.00 per month
Customer Delivery	$1.41 per month	$2.44 per month
Total	**$6.90 per month**	**$11.90 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh		
Description	**Single Phase**	**Three Phase**
Meter Services	$1.20 per month	$2.07 per month
Meter Reading	$0.81 per month	$1.39 per month
Billing & Collection	$3.48 per month	$6.00 per month
Customer Delivery	$1.41 per month	$2.44 per month
LFCR	$2.50 per month	$2.50 per month
Total	**$9.40 per month**	**$14.40 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more		
Description	**Single Phase**	**Three Phase**
Meter Services	$1.20 per month	$2.07 per month
Meter Reading	$0.81 per month	$1.39 per month
Billing & Collection	$3.48 per month	$6.00 per month
Customer Delivery	$1.41 per month	$2.44 per month
LFCR	$6.50 per month	$6.50 per month
Total	**$13.40 per month**	**$18.40 per month**

Filed By: Kentton C. Grant
Title: Vice President of Finance and Rates
District: Entire Electric Service Area

Rate: R-06-01F
Effective: Pending
Decision No.:

DECISION NO. 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 110-3
Superseding:

Energy Charge Components of Delivery Services (Unbundled):

Component	Summer (May – September)	Winter (October - April)
Local Delivery-Energy	$0.013800	$0.011300
Generation Capacity	$0.032700	$0.031100
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge:

	Summer (May – September)	Winter (October - April)
Base Power Component	$0.033198	$0.025698
PPFAC	In accordance with Rider 1 - PPFAC	

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 111
Superseding:

Residential Lifeline Discount (R-06-21F)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

APPLICABILITY
To all single-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.

The discount is also available to tenants of master metered mobile home parks and apartments.

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

ELIGIBILITY
1. The TEP account must be in the customer's name applying for a lifeline discount.
2. Applicant must be a TEP residential customer residing at the premise.
3. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on TEP's website at www.tep.com or contact a TEP customer care representative.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charges:
Standard
Customer Charge, Single Phase service and minimum bill — $ 8.86 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option
Customer Charge, Single Phase with usage less than 2,000 kWh — $11.36 per month
Customer Charge, Single Phase with usage of 2,000 kWh or more — $15.36 per month

Energy Charges ($/kWh):

Summer (May – September)	Delivery Services-Energy[1]	Power Supply Charges[2]		Total[3]
		Base Power	PPFAC	
On-Peak	$0.078800	$0.053198	*varies*	$0.131998
Off-Peak	$0.030100	$0.023198	*varies*	$0.053298

Winter (October – April)	Delivery Services-Energy[1]	Power Supply Charges[2]		Total[3]
		Base Power	PPFAC	
On-Peak	$0.065200	$0.040698	*varies*	$0.105898
Off-Peak	$0.033000	$0.020698	*varies*	$0.053698

DECISION NO. 73912

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 111-1
Superseding:

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY DISCOUNT
The monthly bill shall be in accordance to the rate above except that a discount up to $9.00 per month shall be applied to Delivery Services-Energy and Power Supply Charges. No Lifeline discount will be applied that will reduce the volumetric charges to less than zero.

TIME-OF-USE TIME PERIODS
The Summer On-Peak period is 10:00 a.m. to 10:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

LOST FIXED COST RECOVERY (LFCR) – RIDER 8
For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

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

TEP STATEMENT OF CHARGES
For all charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

Filed By:	Kentton C. Grant	Rate:	R-06-21F
Title:	Vice President of Finance and Rates	Effective:	Pending
District:	Entire Electric Service Area	Decision No.:	

DECISION NO. 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 111-2
Superseding:

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 rate.

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.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Standard	
Description	**Single Phase**
Meter Services	$1.54 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.47 per month
Customer Delivery	$1.82 per month
Total	**$8.86 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh	
Description	**Single Phase**
Meter Services	$1.54 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.47 per month
Customer Delivery	$1.82 per month
LFCR	$2.50 per month
Total	**$11.36 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more	
Description	**Single Phase**
Meter Services	$1.54 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.47 per month
Customer Delivery	$1.82 per month
LFCR	$6.50 per month
Total	**$15.36 per month**

Filed By:	Kentton C. Grant	Rate:	R-06-21F
Title:	Vice President of Finance and Rates	Effective:	Pending
District:	Entire Electric Service Area	Decision No.:	

DECISION NO. 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 111-3
Superseding:

Energy Charge Components of Delivery Services (Unbundled):

Summer (May – September)	On-Peak	Off-Peak
Local Delivery-Energy	$0.011300	$0.011300
Generation Capacity	$0.052900	$0.004200
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge

Summer (May – September)	On-Peak	Off-Peak
Base Power Component	$0.053198	$0.023198
PPFAC	In accordance with Rider 1 - PPFAC	

Energy Charge Components of Delivery Services (Unbundled):

Winter (October – April)	On-Peak	Off-Peak
Local Delivery-Energy	$0.011300	$0.011300
Generation Capacity	$0.039300	$0.007100
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge

Winter (October – April)	On-Peak	Off-Peak
Base Power Component	$0.040698	$0.020698
PPFAC	In accordance with Rider 1 - PPFAC	

DECISION NO. 73912

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 112
Superseding:

Residential Lifeline Discount (R-06-70F)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

APPLICABILITY
To all single-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.

Not applicable to three phase service, 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.

ELIGIBILITY
1. The TEP account must be in the customer's name applying for a lifeline discount.
2. Applicant must be a TEP residential customer residing at the premise.
3. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on TEP's website at www.tep.com or contact a TEP customer care representative.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charges:
Standard
Customer Charge, Single Phase service and minimum bill — $ 8.78 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option
Customer Charge, Single Phase with usage less than 2,000 kWh — $11.28 per month
Customer Charge, Single Phase with usage of 2,000 kWh or more — $15.28 per month

Energy Charges ($/kWh):

Summer (May – September)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC	Total[3]
On-Peak	$0.139300	$0.055698	*varies*	$0.194998
Shoulder	$0.074000	$0.048198	*varies*	$0.122198
Off-Peak	$0.037900	$0.023198	*varies*	$0.061098

Winter (October – April)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC	Total[3]
On-Peak	$0.092500	$0.040698	*varies*	$0.133198
Off-Peak	$0.024900	$0.020698	*varies*	$0.045598

Filed By:	Kentton C. Grant	Rate:	R-06-70F
Title:	Vice President of Finance and Rates	Effective:	Pending
District:	Entire Electric Service Area	Decision No.:	

DECISION NO. 73912

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 112-1
Superseding:

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY DISCOUNT

The monthly bill shall be in accordance to the rate above except that a discount up to $9.00 per month shall be applied to Delivery Services-Energy and Power Supply Charges. No Lifeline discount will be applied that will reduce the volumetric charges to less than zero.

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 1:00 p.m. to 6:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The summer Shoulder period is 6:00 p.m. to 8:00 p.m. Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

LOST FIXED COST RECOVERY (LFCR) – RIDER 8

For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

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 (AZISA) CHARGE

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

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 112-2
Superseding:

TEP STATEMENT OF CHARGES
For all charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

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 rate.

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.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Standard	
Description	**Single Phase**
Meter Services	$1.52 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.43 per month
Customer Delivery	$1.80 per month
Total	**$8.78 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh	
Description	**Single Phase**
Meter Services	$1.52 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.43 per month
Customer Delivery	$1.80 per month
LFCR	$2.50 per month
Total	**$11.28 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more	
Description	**Single Phase**
Meter Services	$1.52 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.43 per month
Customer Delivery	$1.80 per month
LFCR	$6.50 per month
Total	**$15.28 per month**

Filed By: Kentton C. Grant
Title: Vice President of Finance and Rates
District: Entire Electric Service Area

Rate: R-06-70F
Effective: Pending
Decision No.:

DECISION NO. 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 112-3
Superseding:

Energy Charge Components of Delivery Services (Unbundled):

Summer (May – September)	On-Peak	Shoulder-Peak	Off-Peak
Local Delivery-Energy	$0.011300	$0.011300	$0.011300
Generation Capacity	$0.113400	$0.048100	$0.012000
Fixed Must-Run	$0.003000	$0.003000	$0.003000
Transmission	$0.009000	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:			
System Control & Dispatch	$0.000100	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT			

Power Supply Charge

Summer (May – September)	On-Peak	Shoulder-Peak	Off-Peak
Base Power Component	$0.055698	$0.048198	$0.023198
PPFAC	In accordance with Rider 1 - PPFAC		

Energy Charge Components of Delivery Services (Unbundled):

Winter (October – April)	On-Peak	Off-Peak
Local Delivery-Energy	$0.010200	$0.010200
Generation Capacity	$0.067700	$0.000100
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge

Winter (October – April)	On-Peak	Off-Peak
Base Power Component	$0.040698	$0.020698
PPFAC	In accordance with Rider 1 - PPFAC	

DECISION NO. 73912

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 113
Superseding:

Residential Lifeline/Medical Life-Support Discount (R-08-01F)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

APPLICABILITY
To all single phase and 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.

The discount is also available to tenants of master metered mobile home parks and apartments.

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

ELIGIBILITY
1. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on TEP's website at www.tep.com or contact a TEP customer care representative.
2. The applicant must provide documentation to the company that the regular use of a medical life-support device is essential to maintain the life of a full-time resident of the household; or a full-time resident of the household is a paraplegic, quadriplegic or hemiplegic, or a multiple sclerosis or scleroderma patient.
3. A Physician's Verification Form must be completed by the doctor documenting the patient's critical need for electrically powered appliances and describing the needed devices.

CHARACTER OF SERVICE
The service shall be single- or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE-SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge of Delivery Services:

Standard

Customer Charge, Single Phase service and minimum bill	$ 6.90 per month
Customer Charge, Three Phase service and minimum bill	$11.90 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option

Customer Charge, Single Phase with usage less than 2,000 kWh	$ 9.40 per month
Customer Charge, Three Phase with usage less than 2,000 kWh	$14.40 per month
Customer Charge, Single Phase with usage of 2,000 kWh or more	$13.40 per month
Customer Charge, Three Phase with usage of 2,000 kWh or more	$18.40 per month

DECISION NO. 73912

Energy Charges ($/kWh)

	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
Summer (May – September)	$0.061100	$0.033198	varies	$0.094298
Winter (October – April)	$0.057000	$0.025698	varies	$0.082698

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY DISCOUNT
The following monthly discount applies to the rate incorporated herein:

For Bills with Usage of:	Monthly Discount will be applied to the total bill excluding the Customer Charge:
0 – 1000 kWh	35%
1001 – 2000 kWh	30%
Over 2000 kWh	10%

LOST FIXED COST RECOVERY (LFCR) – RIDER 8
For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

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

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 113-2
Superseding:

TEP STATEMENT OF CHARGES
For all charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

AUTOMATED METER OPT-OUT
Residential rate class Customers may request, and have installed, meters that do not transmit data wirelessly. A one-time automated meter opt-out change-out fee, as specified in TEP's Statement of Charges, will apply for the installation of each analog meter that replaces a meter currently in service at the customer's premises that transmits data wirelessly. For a Customer choosing the Automated Meter Opt-out, an additional monthly customer charge as specified in the TEP Statement of Charges will be added to the applicable Customer Charge for as long as the analog meter is left in service.

The Customer may choose to self-read the analog meter. The terms and conditions for self reading of the meter shall be in accordance with Section 10 of the TEP Rules and Regulations.

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 rate.

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.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Standard		
Description	**Single Phase**	**Three Phase**
Meter Services	$1.20 per month	$2.07 per month
Meter Reading	$0.81 per month	$1.39 per month
Billing & Collection	$3.48 per month	$6.00 per month
Customer Delivery	$1.41 per month	$2.44 per month
Total	**$6.90 per month**	**$11.90 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh		
Description	**Single Phase**	**Three Phase**
Meter Services	$1.20 per month	$2.07 per month
Meter Reading	$0.81 per month	$1.39 per month
Billing & Collection	$3.48 per month	$6.00 per month
Customer Delivery	$1.41 per month	$2.44 per month
LFCR	$2.50 per month	$2.50 per month
Total	**$9.40 per month**	**$14.40 per month**

Filed By: Kentton C. Grant
Title: Vice President of Finance and Rates
District: Entire Electric Service Area

Rate: R-08-01F
Effective: Pending
Decision No.:

DECISION NO. 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 113-3
Superseding:

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more		
Description	**Single Phase**	**Three Phase**
Meter Services	$1.20 per month	$2.07 per month
Meter Reading	$0.81 per month	$1.39 per month
Billing & Collection	$3.48 per month	$6.00 per month
Customer Delivery	$1.41 per month	$2.44 per month
LFCR	$6.50 per month	$6.50 per month
Total	**$13.40 per month**	**$18.40 per month**

Energy Charge Components of Delivery Services (Unbundled):

Component	Summer (May – September)	Winter (October - April)
Local Delivery-Energy	$0.013800	$0.011300
Generation Capacity	$0.032700	$0.031100
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge:

	Summer (May – September)	Winter (October - April)
Base Power Component	$0.033198	$0.025698
PPFAC	In accordance with Rider 1 - PPFAC	

DECISION NO. 73912

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 114
Superseding:

Residential Lifeline/Medical Life-Support Discount (R-08-21F)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

APPLICABILITY
To all single 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.

The discount is also available to tenants of master metered mobile home parks and apartments.

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

ELIGIBILITY
1. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on TEP's website at www.tep.com or contact a TEP customer care representative.
2. The applicant must provide documentation to the company that the regular use of a medical life-support device is essential to maintain the life of a full-time resident of the household; or a full-time resident of the household is a paraplegic, quadriplegic or hemiplegic, or a multiple sclerosis or scleroderma patient.
3. A Physician's Verification Form must be completed by the doctor documenting the patient's critical need for electrically powered appliances and describing the needed devices.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery

RATE
A monthly net bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charges:

Standard

Customer Charge, Single Phase service and minimum bill	$ 8.86 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option

Customer Charge, Single Phase with usage less than 2,000 kWh	$11.36 per month
Customer Charge, Single Phase with usage of 2,000 kWh or more	$15.36 per month

DECISION NO. 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 114-1
Superseding:

Energy Charges ($/kWh):

Summer (May – September)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC	Total[3]
On-Peak	$0.078800	$0.053198	*varies*	$0.131998
Off-Peak	$0.030100	$0.023198	*varies*	$0.053298

Winter (October – April)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC	Total[3]
On-Peak	$0.065200	$0.040698	*varies*	$0.105898
Off-Peak	$0.033000	$0.020698	*varies*	$0.053698

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY DISCOUNT
The following monthly discount applies to the rate incorporated herein:

For Bills with Usage of:	Monthly Discount will be applied to the total bill excluding the Customer Charge:
0 – 1000 kWh	35%
1001 – 2000 kWh	30%
Over 2000 kWh	10%

TIME-OF-USE TIME PERIODS
The Summer On-Peak period is 10:00 a.m. to 10:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 114-2
Superseding:

LOST FIXED COST RECOVERY (LFCR) – RIDER 8
For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

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

TEP STATEMENT OF CHARGES
For all charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

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 rate.

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.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Standard	
Description	**Single Phase**
Meter Services	$1.54 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.47 per month
Customer Delivery	$1.82 per month
Total	**$8.86 per month**

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 114-3
Superseding:

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh	
Description	**Single Phase**
Meter Services	$1.54 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.47 per month
Customer Delivery	$1.82 per month
LFCR	$2.50 per month
Total	**$11.36 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more	
Description	**Single Phase**
Meter Services	$1.54 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.47 per month
Customer Delivery	$1.82 per month
LFCR	$6.50 per month
Total	**$15.36 per month**

Energy Charge Components of Delivery Services (Unbundled):

Summer (May – September)	On-Peak	Off-Peak
Local Delivery-Energy	$0.011300	$0.011300
Generation Capacity	$0.052900	$0.004200
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge

Summer (May – September)	On-Peak	Off-Peak
Base Power Component	$0.053198	$0.023198
PPFAC	In accordance with Rider 1 - PPFAC	

Filed By: Kentton C. Grant
Title: Vice President of Finance and Rates
District: Entire Electric Service Area

Rate: R-08-21F
Effective: Pending
Decision No.:

DECISION NO. 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 114-4
Superseding:

Energy Charge Components of Delivery Services (Unbundled):

Winter (October – April)	**On-Peak**	**Off-Peak**
Local Delivery-Energy	$0.011300	$0.011300
Generation Capacity	$0.039300	$0.007100
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge

Winter (October – April)	**On-Peak**	**Off-Peak**
Base Power Component	$0.040698	$0.0020698
PPFAC	*In accordance with Rider 1 - PPFAC*	

DECISION NO. 73912

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 115
Superseding:

Residential Lifeline/Medical Life-Support Discount (R-08-70F)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

APPLICABILITY
To all single 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.

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.

ELIGIBILITY
1. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on TEP's website at www.tep.com or contact a TEP customer care representative.
2. The applicant must provide documentation to the company that the regular use of a medical life-support device is essential to maintain the life of a full-time resident of the household; or a full-time resident of the household is a paraplegic, quadriplegic or hemiplegic, or a multiple sclerosis or scleroderma patient.
3. A Physician's Verification Form must be completed by the doctor documenting the patient's critical need for electrically powered appliances and describing the needed devices.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly net bill at the following rate plus any adjustments incorporated herein:
BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charges:
Standard
Customer Charge, Single Phase service and minimum bill — $8.78 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option
Customer Charge, Single Phase with usage less than 2,000 kWh — $11.28 per month
Customer Charge, Single Phase with usage of 2,000 kWh or more — $15.28 per month

Energy Charges ($/kWh):

Summer (May – September)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC	Total[3]
On-Peak	$0.139300	$0.055698	*varies*	$0.194998
Shoulder	$0.074000	$0.048198	*varies*	$0.122198
Off-Peak	$0.037900	$0.023198	*varies*	$0.061098

Filed By:	Kentton C. Grant	Rate:	R-08-70F
Title:	Vice President of Finance and Rates	Effective:	Pending
District:	Entire Electric Service Area	DecisionNo.:	

DECISION NO. 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 115-1
Superseding:

Winter (October – April)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC	Total[3]
On-Peak	$0.092500	$0.040698	*varies*	$0.133198
Off-Peak	$0.024900	$0.020698	*varies*	$0.045598

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY DISCOUNT
The following monthly discount applies to the rate incorporated herein:

For Bills with Usage of:	Monthly Discount will be applied to the total bill excluding the Customer Charge:
0 – 1000 kWh	35%
1001 – 2000 kWh	30%
Over 2000 kWh	10%

TIME-OF-USE TIME PERIODS
The Summer On-Peak period is 1:00 p.m. to 6:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The summer Shoulder period is 6:00 p.m. to 8:00 p.m. Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

LOST FIXED COST RECOVERY (LFCR) – RIDER 8
For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 115-2
Superseding:

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

TEP STATEMENT OF CHARGES
For all charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

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 rate.

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.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Standard	
Description	**Single Phase**
Meter Services	$1.52 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.43 per month
Customer Delivery	$1.80 per month
Total	**$8.78 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh	
Description	**Single Phase**
Meter Services	$1.52 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.43 per month
Customer Delivery	$1.80 per month
LFCR	$2.50 per month
Total	**$11.28 per month**

Filed By:	Kentton C. Grant	Rate:	R-08-70F
Title:	Vice President of Finance and Rates	Effective:	Pending
District:	Entire Electric Service Area	DecisionNo.:	

DECISION NO. 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 115-3
Superseding:

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more	
Description	Single Phase
Meter Services	$1.52 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.43 per month
Customer Delivery	$1.80 per month
LFCR	$6.50 per month
Total	**$15.28 per month**

Energy Charge Components of Delivery Services (Unbundled):

Summer (May – September)	**On-Peak**	**Shoulder-Peak**	**Off-Peak**
Local Delivery-Energy	$0.011300	$0.011300	$0.011300
Generation Capacity	$0.113400	$0.048100	$0.012000
Fixed Must-Run	$0.003000	$0.003000	$0.003000
Transmission	$0.009000	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:			
System Control & Dispatch	$0.000100	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT			

Power Supply Charge

Summer (May – September)	**On-Peak**	**Shoulder-Peak**	**Off-Peak**
Base Power Component	$0.055698	$0.048198	$0.023198
PPFAC	In accordance with Rider 1 - PPFAC		

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 115-4
Superseding:

Energy Charge Components of Delivery Services (Unbundled):

Winter (October – April)	On-Peak	Off-Peak
Local Delivery-Energy	$0.010200	$0.010200
Generation Capacity	$0.067700	$0.000100
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge

Winter (October – April)	On-Peak	Off-Peak
Base Power Component	$0.040698	$0.020698
PPFAC	In accordance with Rider 1 - PPFAC	

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 116
Superseding:

Residential Lifeline/Medical Life-Support Discount (R-08-201AF)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

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 rate 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 rate. The customer's use of solar energy for any purpose shall not preclude subscription to this rate. The discount is also available to tenants of master metered mobile home parks and apartments.

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

ELIGIBILITY
1. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on TEP's website at www.tep.com or contact a TEP customer care representative.
2. The applicant must provide documentation to the company that the regular use of a medical life-support device is essential to maintain the life of a full-time resident of the household; or a full-time resident of the household is a paraplegic, quadriplegic or hemiplegic, or a multiple sclerosis or scleroderma patient.
3. A Physician's Verification Form must be completed by the doctor documenting the patient's critical need for electrically powered appliances and describing the needed devices.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE-SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge of Delivery Services:
Standard

Customer Charge, Single Phase service and minimum bill	$ 6.90 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option

Customer Charge, Single Phase with usage less than 2,000 kWh	$ 9.40 per month
Customer Charge, Single Phase with usage of 2,000 kWh or more	$13.40 per month

TEP
Tucson Electric Power

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Original Sheet No.: 116-1
Superseding:

Energy Charges ($/kWh)

	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
Mid-Summer (June-August)	$0.061100	$0.033198	*varies*	$0.094298
Remaining-summer (May & September)	$0.043600	$0.033198	*varies*	$0.076798
Winter (October – April)	$0.041300	$0.027198	*varies*	$0.068498

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY DISCOUNT

The following monthly discount applies to the rate incorporated herein:

For Bills with Usage of:	Monthly Discount will be applied to the total bill excluding the Customer Charge:
0 – 1000 kWh	35%
1001 – 2000 kWh	30%
Over 2000 kWh	10%

LOST FIXED COST RECOVERY (LFCR) – RIDER 8

For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

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

TEP STATEMENT OF CHARGES
For all charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

AUTOMATED METER OPT-OUT
Residential rate class Customers may request, and have installed, meters that do not transmit data wirelessly. A one-time automated meter opt-out change-out fee, as specified in TEP's Statement of Charges, will apply for the installation of each analog meter that replaces a meter currently in service at the customer's premises that transmits data wirelessly. For a Customer choosing the Automated Meter Opt-out, an additional monthly customer charge as specified in the TEP Statement of Charges will be added to the applicable Customer Charge for as long as the analog meter is left in service.

The Customer may choose to self-read the analog meter. The terms and conditions for self reading of the meter shall be in accordance with Section 10 of the TEP Rules and Regulations.

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 rate.

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.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

	Standard
Description	**Single Phase**
Meter Services	$1.20 per month
Meter Reading	$0.81 per month
Billing & Collection	$3.48 per month
Customer Delivery	$1.41 per month
Total	**$6.90 per month**

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 116-3
Superseding:

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more	
Description	**Single Phase**
Meter Services	$1.20 per month
Meter Reading	$0.81 per month
Billing & Collection	$3.48 per month
Customer Delivery	$1.41 per month
LFCR	$6.50 per month
Total	**$13.40 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh	
Description	**Single Phase**
Meter Services	$1.20 per month
Meter Reading	$0.81 per month
Billing & Collection	$3.48 per month
Customer Delivery	$1.41 per month
LFCR	$2.50 per month
Total	**$9.40 per month**

Energy Charge Components of Delivery Services (Unbundled):

Component	**Mid Summer** (June -August)	**Remaining Summer** (May & September)	**Winter** (October – April)
Local Delivery-Energy	$0.020600	$0.003100	$0.006800
Generation Capacity	$0.025900	$0.025900	$0.019900
Fixed Must-Run	$0.003000	$0.003000	$0.003000
Transmission	$0.009000	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:			
System Control & Dispatch	$0.000100	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT			

Power Supply Charge:

	Mid Summer (June -August)	**Remaining Summer** (May & September)	**Winter** (October – April)
Base Power Component	$0.033198	$0.033198	$0.027198
PPFAC	In accordance with Rider 1 - PPFAC		

Filed By:	Kentton C. Grant	Rate:	R-08-201AF
Title:	Vice President of Finance and Rates	Effective:	Pending
District:	Entire Electric Service Area	Decision No.:	

DECISION NO. 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 117
Superseding:

Special Residential Electric Service (R-201AN)

AVAILABILITY
Available throughout the Company's entire electric service 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 when all service is supplied at one point of delivery and energy is metered through one meter. Additionally, this Rate requires that the Customer use exclusively the Company's service for all space heating and all water heating energy requirements except as provided below. New homes must conform to the standards of the Company's approved efficiency program for new construction as in effect at the time of subscription to this Rate. Existing homes must conform to certain standards of the Company's approved efficiency program for existing homes as in effect at the time of subscription to this Rate. Company accredited testing and inspection is required for verification. Notwithstanding the above, the Customer's use of solar energy for any purpose shall not preclude subscription to this Rate.

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
The service shall be single phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE – SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charges:

Standard
Customer Charge, Single Phase service and minimum bill — $10.00 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option
Customer Charge, Single Phase with usage less than 2,000 kWh — $12.50 per month
Customer Charge, Single Phase with usage more of 2,000 or more kWh — $16.50 per month

Energy Charges:

Summer (May – September)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
0 – 500 kWh	$0.050600	$0.035111	*varies*	$0.085711
501 – 1,000 kWh	$0.060500	$0.035111	*varies*	$0.095611
1,001 – 3,500 kWh	$0.071800	$0.035111	*varies*	$0.106911
Over 3,500 kWh	$0.079400	$0.035111	*varies*	$0.114511

Winter (October - April)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
0 – 500 kWh	$0.050600	$0.031532	*varies*	$0.082132
501 – 1,000 kWh	$0.058700	$0.031532	*varies*	$0.090232
1,001 – 3,500 kWh	$0.070300	$0.031532	*varies*	$0.101832
Over 3,000 kWh	$0.078400	$0.031532	*varies*	$0.109932

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries),Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

LOST FIXED COST RECOVERY (LFCR) – RIDER 8
For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

MONTHLY LIFELINE DISCOUNT:
This discount is only available to new and eligible Lifeline Customers whose monthly bill shall be in accordance to the rate above except that a discount of $9.00 per month shall be applied. No Lifeline discount will be applied that will reduce the volumetric charges to less than zero.

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

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 117-2
Superseding:

AUTOMATED METER OPT-OUT
Residential rate class Customers may request, and have installed, meters that do not transmit data wirelessly. A one-time automated meter opt-out change-out fee, as specified in TEP's Statement of Charges, will apply for the installation of each analog meter that replaces a meter currently in service at the customer's premises that transmits data wirelessly. For a Customer choosing the Automated Meter Opt-out, an additional monthly customer charge as specified in the TEP Statement of Charges will be added to the applicable Customer Charge for as long as the analog meter is left in service.

The Customer may choose to self-read the analog meter. The terms and conditions for self reading of the meter shall be in accordance with Section 10 of the TEP Rules and Regulations.

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 rate.

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.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Standard	
Description	**Single Phase**
Meter Services	$1.74 per month
Meter Reading	$1.17 per month
Billing & Collection	$5.04 per month
Customer Delivery	$2.05 per month
Total	**$10.00 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh	
Description	**Single Phase**
Meter Services	$1.74 per month
Meter Reading	$1.17 per month
Billing & Collection	$5.04 per month
Customer Delivery	$2.05 per month
LFCR	$2.50 per month
Total	**$12.50 per month**

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 117-3
Superseding:

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more	
Description	Single Phase
Meter Services	$1.74 per month
Meter Reading	$1.17 per month
Billing & Collection	$5.04 per month
Customer Delivery	$2.05 per month
LFCR	$6.50 per month
Total	$16.50 per month

Energy Charge Components of Delivery Services (Unbundled):

Component	Summer (May – September)	Winter (October - April)
Local Delivery-Energy		
Sum First 500 kWh	$0.003400	$0.004100
Sum 501-1,000 kWh	$0.013300	$0.012200
Sum 1,001-3,500 kWh	$0.024600	$0.023800
Sum>3,500 kWh	$0.032200	$0.031900
Generation Capacity	$0.032600	$0.031900
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charges:

Base Power Component	Summer (May – September)	Winter (October - April)
0 – 500 kWh	$0.035111	$0.031532
PPFAC	In accordance with Rider 1 - PPFAC	

Filed By: Kentton C. Grant
Title: Vice President of Finance and Rates
District: Entire Electric Service Area

Rate: R-201AN
Effective: Pending
Decision No.:

DECISION NO. 73912

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 118
Superseding:

Special Residential Electric Service
Time-of-Use Program (R-201BN)

AVAILABILITY
Available throughout the Company's entire electric service 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 when all service is supplied at one point of delivery and energy is metered through one meter. Additionally, this Rate requires that the Customer use exclusively the Company's service for all space heating and all water heating energy requirements except as provided below. New homes must conform to the standards of the Company's approved efficiency program for new construction as in effect at the time of subscription to this Rate. Existing homes must conform to certain standards of the Company's approved efficiency program for existing homes as in effect at the time of subscription to this Rate. Company accredited testing and inspection is required for verification. Notwithstanding the above, the customer's use of solar energy for any purpose shall not preclude subscription to this Rate.

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 this rate for a minimum period of one (1) year.

CHARACTER OF SERVICE
The service shall be single phase, 60 Hertz, and at one nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE – SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charges:

Standard
Customer Charge, Single Phase service and minimum bill — $11.50 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option
Customer Charge, Single Phase with usage less than 2,000 kWh — $14.00 per month
Customer Charge, Single Phase with usage more than 2,000 kWh — $18.00 per month

Energy Charges:

Summer (May – September)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
On-peak	$0.056800	$0.050669	*varies*	$0.107469
Off-peak	$0.044000	$0.026679	*varies*	$0.070679

Filed By:	Kentton C. Grant	Rate:	R-201BN
Title:	Vice President of Finance and Rates	Effective:	Pending
District:	Entire Electric Service Area	Decision No.:	

DECISION NO. 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 118-1
Superseding:

Winter (October - April)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
On-peak	$0.048300	$0.032893	*varies*	$0.081193
Off-peak	$0.035500	$0.027092	varies	$0.062592

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries),Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.
2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.
3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

ELECTRIC VEHICLES

Customers who own and operate Electric Vehicles will receive a 5% discount to the Base Fuel during the off-peak period and the PPFAC. Customers must provide documentation for highway approved Electric Vehicles.

LOST FIXED COST RECOVERY (LFCR) – RIDER 8

For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

MONTHLY LIFELINE DISCOUNT

This discount is only available to new and eligible Lifeline customers whose monthly bill shall be in accordance to the rate above except that a discount of $9.00 per month shall be applied. No Lifeline discount will be applied that will reduce the volumetric charges to less than zero.

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

Tucson Electric Power Company

Original Sheet No.: 118-2
Superseding:

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

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

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 rate.

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.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Standard	
Description	**Single Phase**
Meter Services	$2.00 per month
Meter Reading	$1.34 per month
Billing & Collection	$5.80 per month
Customer Delivery	$2.36 per month
Total	**$11.50 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh	
Description	**Single Phase**
Meter Services	$2.00 per month
Meter Reading	$1.34 per month
Billing & Collection	$5.80 per month
Customer Delivery	$2.36 per month
LFCR	$2.50 per month
Total	**$14.00 per month**

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 118-3
Superseding:

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more	
Description	**Single Phase**
Meter Services	$2.00 per month
Meter Reading	$1.34 per month
Billing & Collection	$5.80 per month
Customer Delivery	$2.36 per month
LFCR	$6.50 per month
Total	$18.00 per month

Energy Charge Components (Unbundled)

Summer (May – September)	On-Peak	Off-Peak
Delivery-Energy	$0.011300	$0.011300
Generation Capacity	$0.030900	$0.018100
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		
Base Power Supply Charge	$0.050669	$0.026679
PPFAC	In accordance with Rider 1 – PPFAC	

Winter (October - April)	On-Peak	Off-Peak
Delivery-Energy	$0.011300	$0.011300
Generation Capacity	$0.022400	$0.009600
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		
Base Power Supply Charge	$0.032893	$0.027092
PPFAC	In accordance with Rider 1 – PPFAC	

Filed By: Kentton C. Grant
Title: Vice President of Finance and Rates
District: Entire Electric Service Area

Rate: R-201BN
Effective: Pending
Decision No.:

DECISION NO. 73912

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 201
Superseding:

Small General Service (GS-10)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises. To all general power and lighting service unless otherwise addressed by specific Rates.

APPLICABILITY
When all energy is supplied at one point of delivery and through one metered service. Not applicable to resale, breakdown, temporary, standby, or auxiliary service.

The supply of electric service under a residential Rate schedule to a dwelling involving some business or professional activity will be permitted only where such activity is of only occasional occurrence, or where the electricity used in connection with such activity is small in amount and used only by equipment which would normally be in use if the space were used as living quarters. Where the portion of a dwelling is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electrical equipment not normally used in living quarters is installed in connection with such activities referred to above, the entire premises must be classified as non-residential and the appropriate general service rate will be applied.

For Customers who were previously on Municipal Service Rate (PS-40), a monthly transitional adjustment of 16.5% will be applied to the total bill excluding the Customer Charge.

CHARACTER OF SERVICE
The service shall be 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.

RATE
A monthly bill at the following rate, plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE – SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charges:
Customer Charge, Single Phase service and minimum bill $15.50 per month
Customer Charge, Three Phase service and minimum bill $20.50 per month

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

Delivery Charges:

Description	Summer (May – September)	Winter (October – April)
First 500 kWh	$0.076800	$0.056800
All remaining kWh	$0.097600	$0.078800

Base Power Supply Charges:
Summer $0.035111 per kWh
Winter $0.031532 per kWh

Filed By:	Kentton C. Grant	Rate:	GS-10
Title:	Vice President of Finance and Rates	Effective:	Pending
District:	Entire Electric Service Area	Decision No.:	

DECISION NO. 73912

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply 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.

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 (AZISA) CHARGE

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

TEP STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

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 rate.

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.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Description	Single Phase	Three Phase
Meter Services	$5.78 per month	$7.65 per month
Meter Reading	$0.74 per month	$0.98 per month
Billing & Collection	$3.19 per month	$4.21 per month
Customer Delivery	$5.79 per month	$7.66 per month
Total	**$15.50 per month**	**$20.50 per month**

Energy Charge Components (Unbundled):

Component	Summer (May - September)	Winter (October - April)
Delivery-Energy		
First 500 kWh	$0.021700	$0.021700
All remaining kWh	$0.022600	$0.022600
Generation Capacity		
First 500 kWh	$0.042700	$0.022700
All remaining kWh	$0.062600	$0.043800
Fixed Must-Run	$0.003500	$0.003500
Transmission	$0.006800	$0.006800
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000400	$0.000400
Regulation and Frequency Response	$0.000400	$0.000400
Spinning Reserve Service	$0.001000	$0.001000
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		
Base Power Supply Charge	$0.035111	$0.031532
PPFAC	In accordance with Rider 1 - PPFAC	

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 202
Superseding:

Mobile Home Park Electric Service (GS-11F)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

APPLICABILITY
To mobile home parks for service through a master meter to two or more mobile homes, provided each mobile home served through such master meter will be individually metered and billed by the park operator in accordance with applicable Orders of the Arizona Corporation Commission. Electric service to the park's facilities used by its residents may be supplied under this schedule only if such facilities are served through a master meter which serves two or more mobile homes.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service.

CHARACTER OF SERVICE
The service shall be 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.

RATE
A monthly bill at the following rate, plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE – SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charges:

Customer Charge, Single Phase service and minimum bill	$15.50 per month
Customer Charge, Three Phase service and minimum bill	$20.50 per month

Energy Charges:

Delivery Charge	
Summer (May – September), all kWh	$0.082000 per kWh
Winter (October – April), all kWh	$0.062000 per kWh

Base Power Charges:

Delivery Charge	$0.035111 per kWh
Summer (May – September), all kWh	$0.031532 per kWh
Winter (October – April), all kWh	

Purchased Power and Fuel Adjustment Clause ("PPFAC"): The Base Power Supply 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.

ADJUSTMENT FOR TRANSFORMER OWNERSHIP AND METERING
When Customer owns transformers and energy is metered on primary side of transformers, the demand shall be metered and the above schedule subject to a discount of 20.6¢ per kW per month of the demand each month.

Filed By:	Kentton C. Grant	Rate:	GS-11F
Title:	Vice President of Finance and Rates	Effective:	Pending
District:	Entire Electric Service Area	Decision No.:	

DECISION NO. 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 202-1
Superseding:

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

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

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 rate.

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.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Description	Single Phase	Three Phase
Meter Services	$5.78 per month	$7.65 per month
Meter Reading	$0.74 per month	$0.98 per month
Billing & Collection	$3.19 per month	$4.21 per month
Customer Delivery	$5.79 per month	$7.66 per month
Total	**$15.50 per month**	**$20.50 per month**

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 202-2
Superseding:

Energy Charge Components (Unbundled):

Component	Summer (May – September)	Winter (October - April)
Local Delivery-Energy	$0.021700	$0.021700
Generation Capacity	$0.047900	$0.027900
Fixed Must-Run	$0.003500	$0.003500
Transmission	$0.006800	$0.006800
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000400	$0.000400
Regulation and Frequency Response	$0.000400	$0.000400
Spinning Reserve Service	$0.001000	$0.001000
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		
Base Power Supply Charge	$0.035111	$0.031532
PPFAC	In accordance with Rider 1 - PPFAC	

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 203
Superseding:

Small General Service
Time-of-Use Program (GS-76)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises. Access to the meter during normal working hours is also a prerequisite for this Rate.

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, temporary, standby, or auxiliary service. Service under this Rate will commence when the appropriate meter has been installed.

Customers must stay on this Rate for a minimum period of one (1) year.

CHARACTER OF SERVICE
The service shall be single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge:

Customer Charge, single or three phase service and minimum bill $17.50 per month

Energy Charges:

Description	Summer (May – September)	Winter (October - April)
On-Peak kWh	$0.098700	$0.081000
Off-Peak kWh	$0.084500	$0.064500

Base Power Supply Charges:

Summer On-Peak	$0.050669 per kWh
Summer Off-Peak	$0.026679 per kWh
Winter On-Peak	$0.032893 per kWh
Winter Off-Peak	$0.027092 per kWh

Purchased Power and Fuel Adjustment Clause ("PPFAC"): The Base Power Supply 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.

Filed By:	Kentton C. Grant	Rate:	GS-76
Title:	Vice President of Finance and Rates	Effective:	Pending
District:	Entire Electric Service Area	Decision No.:	

DECISION NO. 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 203-1
Superseding:

TIME-OF-USE TIME PERIODS
The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

ADJUSTMENT FOR TRANSFORMER OWNERSHIP AND METERING
When Customer owns transformers and energy is metered on primary side of transformers, the demand shall be metered and the above schedule subject to a discount of 20.6¢ per kW per month of the billing demand each month.

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

PRIMARY SERVICE
The Rates contained in this Schedule are designed to reflect secondary service but where service is taken at primary voltage will be subject to a primary discount of 20.6 cents per kW per month (on the bundled rate, with the discount taken from the unbundled kW delivery charge) on the billing demand each month.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

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 rate.

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

Tucson Electric Power Company

Original Sheet No.: 203-2
Superseding:

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Description	Customer Charge
Meter Services	$6.53 per month
Meter Reading	$0.83 per month
Billing & Collection	$3.60 per month
Customer Delivery	$6.54 per month
Total	**$17.50 per month**

Energy Charge Components (Unbundled)

Summer (May – September)	On-Peak	Off-Peak
Local Delivery-Energy[1]	$0.022300	$0.022300
Generation Capacity	$0.064000	$0.049800
Fixed Must-Run	$0.003500	$0.003500
Transmission	$0.006800	$0.006800
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000400	$0.000400
Regulation and Frequency Response	$0.000400	$0.000400
Spinning Reserve Service	$0.001000	$0.001000
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT.		
Base Power Supply Charge	$0.050669	$0.026679
PPFAC	In accordance with Rider 1 - PPFAC	

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 203-3
Superseding:

Energy Charge Components (Unbundled)

Winter (October - April)	On-Peak	Off-Peak
Delivery-Energy	$0.022300	$0.022300
Generation Capacity	$0.046300	$0.029800
Fixed Must-Run	$0.003500	$0.003500
Transmission	$0.006800	$0.006800
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000400	$0.000400
Regulation and Frequency Response	$0.000400	$0.000400
Spinning Reserve Service	$0.001000	$0.001000
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		
Base Power Supply Charge	$0.032893	$0.027092
PPFAC	In accordance with Rider 1 - PPFAC	

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 204
Superseding:

Large General Service (LGS-13)

AVAILABILITY
Available throughout the Company's entire electric service 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 on an optional basis when all energy is supplied at one point of delivery and through one metered service. The minimum monthly billing demand hereunder is 200 kW.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service.

CHARACTER OF SERVICE
The service shall be 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 shall be required for new installations with service requirements in excess of 2,500 kW.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE – SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge:	$775.00 per month
Demand Charge:	$15.25 per kW
Energy Charges:	
Summer (May – September)	$0.019200 per kWh
Winter (October – April)	$0.013400 per kWh
Base Power Charges:	
Summer (May – September)	$0.035111 per kWh
Winter (October – April)	$0.031532 per kWh

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply 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.

BILLING DEMAND
The monthly billing demand shall be the greatest of the following:

1. The maximum 15 minute measured demand in the billing month;
2. 75 % of the maximum demand used for billing purposes in the preceding 11 months; or
3. The contract demand amount, not to be less than 200 kW.

ADJUSTMENT FOR PRIMARY SERVICE AND METERING
When Customer owns transformers and energy is metered on primary side of transformers, the demand shall be metered and the above schedule subject to a discount of 20.6¢ per kW per month of the billing demand each month.

The Company may require a written contract with a minimum contract demand and a minimum term of contract.

TEP

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 204-1
Superseding:

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

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

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 rate.

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.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:	
Meter Services	$211.38 per month
Meter Reading	$ 32.43 per month
Billing & Collection	$140.81 per month
Customer Delivery	$390.38 per month
Total	**$775.00 per month**
Demand Charge (in $/kW):	
Delivery Charge	$1.71 per kW
Generation Capacity	$9.17 per kW
Fixed Must-Run	$0.95 per kW
Transmission	$2.67 per kW
Transmission Ancillary Services	
System Control & Dispatch	$0.04 per kW
Reactive Supply and Voltage Control	$0.14 per kW
Regulation and Frequency Response	$0.14 per kW
Spinning Reserve Service	$0.37 per kW

DECISION NO. 73912

Supplemental Reserve Service	$0.06 per kW
Energy Imbalance Service: Currently charged pursuant to the Company's OATT	

Energy Charges (kWh): (in $/kWh)

Delivery Charge	
Summer	$0.005800 per kWh
Winter	$0.004000 per kWh
Generation Capacity	
Summer	$0.013400 per kWh
Winter	$0.009400 per kWh
Base Power Supply Charge	
Summer	$0.035111 per kWh
Winter	$0.031532 per kWh

DECISION NO. 73912

Docket No. E-01933A-12-0291

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 205
Superseding:

Large General Service
Time-of-Use Program (LGS-85)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises. To all general power and lighting service unless otherwise addressed by specific rate schedules.

APPLICABILITY
When all energy is supplied at one point of delivery and through one metered service. Not applicable to resale, breakdown, temporary, standby, or auxiliary service. Service under this Rate will commence when the appropriate meter has been installed.

The minimum monthly billing demand hereunder is 200 kW.

Customers must stay on this Rate for a minimum period of one (1) year.

CHARACTER OF SERVICE
The service shall be 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 shall be required for new installations with service requirements in excess of 2,500 kW.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge and minimum bill $950.00 per month

Demand Charges (includes Generation Capacity):
Summer On-peak $14.55 per kW
Summer Off-peak (applies to all off-peak demand bill determinates) $10.92 per kW

Winter On-peak $11.59 per kW
Winter Off-peak Demand (applies to all off-peak demand bill determinates) $ 9.10 per kW

Note:
1. *For demand billing, "on-peak demand" shall be based on demand measured during peak periods.*
2. *For demand billing, "off-peak demand" shall be based on demand measured during the off- peak periods.*
3. *Unlike Schedule LLP Rate 90 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.*

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

Delivery Charges ($/kWh)

	Summer (May – September)	Winter (October - April)
On-Peak	$0.008600	$0.003000
Off-Peak	$0.006000	$0.000500

Filed By: Kentton C. Grant
Title: Vice President of Finance and Rates
District: Entire Electric Service Area

Rate: LGS-85
Effective: Pending
Decision No.:

DECISION NO. 73912

TIME-OF-USE TIME PERIODS
The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

Base Power Supply Charges ($/kWh)

	Summer (May – September)	Winter (October – April)
On-Peak	$0.050669	$0.032893
Off-Peak	$0.026679	$0.027092

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply 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.

DETERMINATION OF BILLING DEMAND
The monthly billing demand shall be the combination of the following;

The greatest of the following during the On-Peak period:

1. The maximum 15 minute measured demand during the on-peak period of the billing month;
2. 75% of the maximum on-peak period billing demand used for billing purposes in the preceding 11 months; or
3. The contract demand amount, not to be less than 200 kW, and

The greatest of the following during the Off-peak period:

1. The maximum 15 minute measured demand during the off-peak period of the billing month;
2. 75% of the maximum off-peak period billing demand used for billing purposes in the preceding 11 months; or
3. The contract demand amount, not to be less than 200 kW.

PRIMARY SERVICE
The Rates contained in this Schedule are designed to reflect secondary service but where service is taken at a primary voltage discount of 20.6 cents per kW per month (on the bundled rate, with the discount taken from the unbundled kW delivery charge) will be applied to the billing demand each month.

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

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 205-2
Superseding:

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

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 rate.

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.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:	
Meter Services	$259.11 per month
Meter Reading	$ 39.75 per month
Billing & Collection	$172.61 per month
Customer Delivery	$478.53 per month
	$950.00 per month
Demand Charges ($/kW)	
Generation Capacity Charges (in $/kW)	
Summer On-peak	$10.18 per kW
Summer Off-peak	$ 6.55 per kW
Winter On-peak	$ 7.22 per kW
Winter Off-peak	$ 4.73 per kW
Fixed Must-Run Charges (in $/kW)	$ 0.95 per kW
Transmission (in $/kW)	$ 2.67 per kW
Transmission - Ancillary Services System Control & Dispatch (in $/kW)	
System Control & Dispatch	$ 0.04 per kW
Reactive Supply and Voltage Control	$ 0.14 per kW
Regulation and Frequency Response	$ 0.14 per kW
Spinning Reserve Service	$ 0.37 per kW
Supplemental Reserve Service	$ 0.06 per kW
Energy Imbalance Service: Currently charged pursuant to the Company's OATT	

DECISION NO. 73912

TEP
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Tucson Electric Power Company

Original Sheet No.: 205-3
Superseding:

Energy Charges ($/kWh):

Delivery Charges	
Summer On-peak	$0.002600 per kWh
Summer Off-peak	$0.001800 per kWh
Winter On-peak	$0.000900 per kWh
Winter Off-peak	$0.000150 per kWh
Generation Capacity	
Summer On-peak	$0.006000 per kWh
Summer Off-peak	$0.004200 per kWh
Winter On-peak	$0.002100 per kWh
Winter Off-peak	$0.000350 per kWh
Base Power Supply Charge	
Summer On-peak	$0.050669 per kWh
Summer Off-peak	$0.026679 per kWh
Winter On-peak	$0.032893 per kWh
Winter Off-peak	$0.027092 per kWh

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 301
Superseding:

Large Light and Power Service (LLP-14)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all large general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service. The minimum monthly billing demand hereunder is 3,000 kW.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service.

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.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE – SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge:	$1,800 per month
Demand Charge:	$21.98 per kW
Energy Charges:	
Summer (May – September)	$0.003200 per kWh
Winter (October – April)	$0.002100 per kWh
Base Power Charges:	
Summer (May – September)	$0.031611 per kWh
Winter (October - April	$0.028388 per kWh

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply 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.

BILLING DEMAND
The monthly billing demand shall be the grestest of the following:

1. The maximum 15 minute measured demand in the billing month;
2. 75 % of the maximum demand used for billing purposes in the preceding 11 months; or
3. The contract demand amount, not to be less than 3,000 kW.

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 the transformer.

POWER FACTOR ADJUSTMENT
The above rate is subject to a charge of 1.3¢ per kW of billing demand for each 1% the average monthly power factor is below 100%

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

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

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 rate.

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.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:	
Meter Services	$ 449.66 per month
Meter Reading	$ 74.29 per month
Billing & Collection	$ 323.56 per month
Customer Delivery	$ 952.49 per month
Total	**$1,800.00 per month**
Demand Charges:	
Delivery Charge (in $/kW)	$ 1.69 per kW
Generation Capacity Charges (in $/kW)	$14.40 per kW
Fixed Must-Run Charges (in $/kW)	$ 0.97 per kW
Transmission (in$/kW)	$ 3.84 per kW
Transmission Ancillary Services (in $/kW)	
System Control & Dispatch	$ 0.05 per kW
Reactive Supply and Voltage Control	$ 0.20 per kW

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Original Sheet No.: 301-2
Superseding:

Regulation and Frequency Response	$ 0.20 per kW
Spinning Reserve Service	$ 0.54 per kW
Supplemental Reserve Service	$ 0.09 per kW

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

Energy Charges: (in $/kWh)

Delivery Charges

Summer	$0.003200 per kWh
Winter	$0.002100 per kWh

Base Power Supply Charges

Summer	$0.031611 per kWh
Winter	$0.028388 per kWh

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 302
Superseding:

Large Light and Power Service
Time of Use Program (LLP-90)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all large general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service. The minimum monthly billing demand hereunder is 3000 kW.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service.

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.

Customers must stay on this Rate for a minimum period of one (1) year.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE – SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge and minimum bill $2,000.00 per month

Demand Charges (includes Generation Capacity):

Summer On-peak	$20.49 per kW
Summer Off-peak Excess Demand	$12.49 per kW
Winter On-peak	$15.49 per kW
Winter Off-peak Excess Demand	$9.99 per kW

Note:
1. *For demand billing, "on-peak demand" shall be based on demand measured during peak periods.*
2. *For demand billing, "off-peak demand" shall be based on demand measured during the off- peak periods.*

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

Delivery Charges ($/kWh):

	Summer (May – September)	Winter (October – April)
On-Peak	$0.006900	$0.007500
Off-Peak	$0.006500	$0.007100

Filed By:	Kentton C. Grant	Rate:	LLP-90
Title:	Vice President of Finance and Rates	Effective:	Pending
District:	Entire Electric Service Area	Decision No.:	

73912
DECISION NO.

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

Base Power Supply Charges ($/kWh)

	Summer (May – September)	Winter (October – April)
On-Peak	$0.045568	$0.029581
Off-Peak	$0.023985	$0.024352

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply 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.

DETERMINATION OF BILLING DEMAND

The greatest of the following:

1. The maximum 15 minute measured demand during the on-peak period of the billing month;
2. 75% of the maximum on-peak period billing demand used for billing purposes in the preceding 11 months; or
3. The contract demand amount, not to be less than 3,000 kW, and

Additionally, the maximum 15 minute measured demand during the off-peak period of the billing month that is in excess (i.e. positive incremental amount above) of 150% of that billing month's on-peak measured billing demand.

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 charge of 1.3¢ per kW of billing demand for each 1% the average monthly power factor is below 100%.

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 (AZISA) CHARGE

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

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

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 rate.

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.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:	
Meter Services	$499.63 per month
Meter Reading	$82.53 per month
Billing & Collection	$359.51 per month
Customer Delivery	$1,058.33 per month
	$2,000.00 per month
Demand Charges ($/kW)	
Delivery Charges	
Summer & Winter On-peak	$1.69 per kW
Summer & Winter Excess Demand	$1.61 per kW
Generation Capacity Charges (in $/kW)	
Summer On-peak	$12.91 per kW
Summer Excess Demand	$ 6.27 per kW
Winter On-peak	$ 7.91 per kW
Winter Excess Demand	$ 3.77 per kW
Fixed Must Run Charges (in $/kW)	
Summer & Winter On-peak	$ 0.97 per kW
Summer & Winter Off-peak Excess Demand	$ 0.92 per kW
Transmission (in $/kW)	
Summer & Winter On-peak	$ 3.84 per kW
Summer & Winter Excess Demand (kW)	$ 2.88 per kW
Transmission - Ancillary System Control	
Summer & Winter On-peak	$ 0.05 per kW
Summer & Winter Excess Demand (kW)	$ 0.04 per kW

DECISION NO. 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 302-3
Superseding:

Transmission – Ancillary Reactive Supply	
Summer & Winter On-peak	$ 0.20 per kW
Summer & Winter Excess Demand (kW)	$ 0.15 per kW
Transmission - Ancillary Frequency Response	
Summer & Winter On-peak	$ 0.20 per kW
Summer & Winter Excess Demand (kW)	$ 0.15 per kW
Transmission - Ancillary Spinning Reserve	
Summer & Winter On-peak	$ 0.54 per kW
Summer & Winter Excess Demand (kW)	$ 0.40 per kW
Transmission - Ancillary Supplemental Reserve	
Summer & Winter On-peak	$ 0.09 per kW
Summer & Winter Excess Demand (kW)	$ 0.07 per kW

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

Energy Charges ($/kWh)

Delivery Charges (in $/kWh)	
Summer On-peak	$0.006900 per kWh
Summer Off-peak Excess Demand	$0.006500 per kWh
Winter On-peak	$0.007500 per kWh
Winter Off-peak Excess Demand	$0.007100 per kWh

Base Power Supply Charges

Summer	
On-Peak	$0.045568 per kWh
Off-Peak	$0.023985 per hWh
Winter	
On-Peak	$0.029581 per kWh
Off-Peak	$0.024352 per kWh

Docket No. E-01933A-12-0291

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 501
Superseding:

Traffic Signal and Street Lighting Service (PS-41)

AVAILABILITY
Available for service to the State, a county, city, town, political subdivision, improvement district, or a responsible person or persons for unincorporated communities for Traffic Signal and Street Lighting purposes where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
Applicable to Customer owned and maintained traffic signals and public street and highway lighting.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service.

CHARACTER OF SERVICE
Service shall be single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery approved by the Company.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein.

BUNDLED STANDARD OFFER SERVICE – SUMMARY OF CUSTOMER AND ENERGY CHARGES

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

Delivery Charge	$0.047600 per kWh
Base Power Charges:	
Summer (May – September)	$0.035111 per kWh
Winter (October – April)	$0.031532 per kWh

Purchased Power and Fuel Adjustment Clause ("PPFAC"): The Base Power Supply 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.

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 rate will be applied to the customer's bill.

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

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

Filed By:	Kentton C. Grant	Rate:	PS-41
Title:	Vice President of Finance and Rates	Effective:	Pending
District:	Entire Electric Service Area	Decision No.:	

DECISION NO. 73912

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 501-1
Superseding:

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 rate.

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.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

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

Delivery Charge (in $/kWh)	
Summer	$0.003400 per kWh
Winter	$0.003400 per kWh
Generation Capacity (in $/kWh)	
Summer	$0.010200 per kWh
Winter	$0.010200 per kWh
Fixed Must-Run (in $/kWh)	$0.014300 per kWh
Transmission (in $/kWh)	$0.015300 per kWh
Transmission Ancillary Services (in $/kWh)	
System Control & Dispatch	$0.000200 per kWh
Reactive Supply and Voltage Control	$0.000800 per kWh
Regulation and Frequency Response	$0.000800 per kWh
Spinning Reserve Service	$0.002200 per kWh
Supplemental Reserve Service	$0.000400 per kWh
Energy Imbalance Service: Currently charged pursuant to the Company's OATT.	
Base Power Supply Charge	
Summer	$0.035111 per kWh
Winter	$0.031532 per kWh

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 502
Superseding:

Lighting Service (PS-50)

AVAILABILITY
At any point where the Company in its judgment has facilities of adequate capacity and suitable voltage available.

APPLICABILITY
Applicable to any Customer for private and public street lighting or outdoor area lighting where this service can be supplied from existing facilities of the Company.

The Company will install, own, operate, and maintain the complete lighting installation including lamp and globe replacements. Not applicable to resale service.

CHARACTER OF SERVICE
Multiple or series street lighting system at option of Company and at one standard nominal voltage.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein.

BUNDLED STANDARD OFFER SERVICE – SUMMARY OF CUSTOMER AND ENERGY CHARGES

Delivery Charge:

Service	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt	Underground Service	Pole
Per unit Per month	$8.19	$8.19	$8.19	$12.29	$18.70	$15.53	$2.86

Note:

The watt high pressure sodium lamps are charged per unit per month.

Per one pole addition and an extension of up to 100 feet of overhead service are charged per pole.

Underground Service is per 100 watt or less high pressure sodium lamp unit per month mounted on standard pole.

Base Power Supply Charge:

Service	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt	Underground Service	Pole
Per unit Per month	$0.85	$0.94	$1.34	$3.36	$5.38	$0.00	$0.00

Purchased Power and Fuel Adjustment Clause ("PPFAC"): The Base Power Supply 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.

STANDARD LAMP UNITS, OVERHEAD SERVICE

1. The standard 100 watt lamp unit for overhead service is a 9,500 lumen high pressure sodium unit, mounted on a six (6) foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately twenty-five (25) feet above ground level and is for public and private street lighting and area lighting.

2. The standard 250 watt lamp unit for overhead service is a 27,500 lumen high pressure sodium unit, mounted on a twelve (12) foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately twenty-seven (27) feet above ground level and is for public and private street lighting.

3. The standard 400 watt lamp unit for overhead service is a 50,000 lumen high pressure sodium unit, mounted on an eighteen (18) foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately thirty-five (35) feet above ground level and is for public and private street lighting.

4. The standard 100 watt lamp unit for underground service is a 9,500 lumen high pressure sodium post top unit mounted on a pole approximately fifteen (15) feet above ground level and is for public and private street lighting and area lighting.

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 herein will be applied to the Customer's bill.

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

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

SPECIAL PROVISIONS

1. Installation of a light on an existing pole is subject to prior approval of Company.

2. For underground service up to ten (10) feet from the electrical source, the Customer shall be billed at the rates for overhead service.

3. Extensions beyond 100 feet and all installations other than those addressed in this rate will require specific agreements providing adequate revenue or arrangements for construction financing.

4. The Customer is not authorized to make connections to this lighting circuit or to make attachments or alterations to the Company owned pole.

5. If a Customer requests a relocation of a lighting installation, the costs of such relocation must be borne by the Customer.

6. The Customer is expected to notify the Company when lamp outages occur.

7. The Company will use diligence in maintaining service; however, monthly bills will not be reduced because of lamp outages.

8. After the minimum contract period, if any, has expired, this agreement shall be extended from year to year unless written notice of desire to terminate is given by the Customer at least thirty (30) days prior to the end of any such annual extension date. The Company reserves the right not to extend or cancel the lighting agreement at any time after the initial minimum contract period has expired.

9. Light installation is subject to the governmental agency approval process.

10. The Customer is responsible for all civil installation requirements as specified by the Company in accordance with the Electrical Service Requirements.

11. In the event a public improvement project conflict(s) with existing lighting facilities, the impacted facilities will be removed.

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 rate.

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

Tucson Electric Power Company

Original Sheet No.: 502-3
Superseding:

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Delivery Components:	
50, 70, 100 Watt ($/Unit)	$ 0.71 Per Unit
250 Watt ($/Unit)	$ 4.81 Per Unit
400 Watt ($/Unit)	$ 11.22 Per Unit
Generation Capacity ($/Unit)	$ 1.50 Per Unit
Fixed Must Run ($/Unit)	$ 2.84 Per Unit
Transmission (in $/kWh)	$ 2.45 Per Unit
Transmission Ancillary Services (kn $/kWh)	
System Control & Dispatch	$ 0.0300 Per Unit
Reactive Supply and Voltage Control	$ 0.1300 Per Unit
Regulation and Frequency Response	$ 0.1300 Per Unit
Spinning Reserve Service	$ 0.3400 Per Unit
Supplemental Reserve Service	$ 0.0600 Per Unit

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

Base Power Supply Charge

Service	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt
Per unit Per month	$0.85	$0.94	$1.34	$3.36	$5.38

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 601
Superseding:

Water Pumping Service (GS-43)

AVAILABILITY
Available for service to the City of Tucson Water Utility and private water Companies where the facilities of the Company are of adequate capacity and are adjacent to the premises.

Available for interruptible service agricultural pumping customers throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

The service points being billed under the PS-43 and GS-31 rate classes as of the effective date of this tariff, but do not meet the above criteria, will be allowed to stay on this rate as long as they meet all other requirements specified in the tariff.

APPLICABILITY
Applicable for service to booster stations and wells used for domestic water supply. For Interruptible service this is applicable to separately metered interruptible agricultural water pumping service for irrigation purposes of the Customer only.
Not applicable to resale, breakdown, temporary, standby, or auxiliary service.

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

RATE
A monthly bill at the following rate plus any adjustments incorporated herein.

BUNDLED STANDARD OFFER SERVICE – SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge: $15.50 per month

Energy Charges:

Firm Service
Delivery Charge
Summer (May – September) $0.068000 per kWh
Winter (October – April) $0.048000 per kWh

Interruptible Service
Delivery Charge
Summer (May – September) $0.042000 per kWh
Winter (October – April) $0.027000 per kWh

Base Power Supply Charges:

	Summer (May-September)	Winter (October – April)
Firm Service	$0.035111	$0.031532
Interruptible Service	$0.031310	$0.028420

Purchased Power and Fuel Adjustment Clause ("PPFAC"): The Base Power Supply 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.

Primary Voltage Discount
A discount of 5% will be allowed from the above rates where Customer owns the transformers and service is metered at primary voltage.

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

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TERMS AND CONDITIONS OF INTERRUPTIBLE SERVICE

1. Customer must furnish, install, own, and maintain at each point of delivery all necessary Company approved equipment which will enable the Company to interrupt service with its master control station.

2. Service may be interrupted by Company during certain periods of the day not exceeding six hours in any 24-hour period.

3. Company will endeavor to give Customer one hour notice of impending interruption; however, service may be interrupted without notice should Company deem such action necessary.

4. The interruptible load shall be separately served and metered and shall at no time be connected to facilities serving Customer's firm load. Conversely, the firm load shall be separately served and metered and shall at no time be connected to facilities serving Customer's interruptible load.

5. Company shall not be liable for any loss or damage caused by or resulting from any interruption of 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 rate.

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.

DECISION NO. 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 601-2
Superseding:

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Firm Service

Customer Charge Components (Unbundled):

Description	Customer Charge
Meter Services	$5.78 per month
Meter Reading	$0.74 per month
Billing & Collection	$3.19 per month
Customer Delivery	$5.79 per month
Total	**$15.50 per month**

Energy Charge Components (Unbundled):

Component	Summer (May – September)	Winter (October - April)
Local Delivery-Energy	$0.021700	$0.021700
Generation Capacity	$0.033900	$0.013900
Fixed Must-Run	$0.003500	$0.003500
Transmission	$0.006800	$0.006800
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000400	$0.000400
Regulation and Frequency Response	$0.000400	$0.0004
Spinning Reserve Service	$0.001000	$0.001000
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		
Base Power Supply Charge	$0.035111	$0.031532
PPFAC	In accordance with Rider 1 - PPFAC	

Filed By: Kentton C. Grant
Title: Vice President of Finance and Rates
District: Entire Electric Service Area

Rate: GS-43
Effective: Pending
Decision No.:

DECISION NO. 73912

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 601-3
Superseding:

Interruptible Service

Customer Charge Components (Unbundled):

Description	Customer Charge
Meter Services	$5.78 per month
Meter Reading	$0.74 per month
Billing & Collection	$3.19 per month
Customer Delivery	$5.79 per month
Total	**$15.50 per month**

Energy Charge Components (Unbundled):

Component	Summer (May – September)	Winter (October - April)
Local Delivery-Energy	$0.021700	$0.007900
Generation Capacity	$0.007900	$0.006700
Fixed Must-Run	$0.003500	$0.003500
Transmission	$0.006800	$0.006800
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000400	$0.000400
Regulation and Frequency Response	$0.000400	$0.000400
Spinning Reserve Service	$0.001000	$0.001000
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		
Base Power Supply Charge	$0.031310	$0.028420
PPFAC	In accordance with Rider 1 - PPFAC	

Filed By: Kentton C. Grant
Title: Vice President of Finance and Rates
District: Entire Electric Service Area

Rate: GS-43
Effective: Pending
Decision No.:

DECISION NO. 73912

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 701
Superseding:

Rider R-1
Purchased Power and Fuel Adjustment Clause (PPFAC)

APPLICABILITY
The Purchased Power and Fuel Adjustment Clause (PPFAC) will be applied to all Customers taking Standard Offer service from the Company pursuant to the Arizona Corporation Commission (ACC) Decision No. XXXXX dated XXXXXX XX, 2013 and as updated and defined in the Company's PPFAC Plan of Administration approved in ACC Decision No. XXXXX.

RATE
The Customer monthly bill shall consist of the applicable Rate, charges and adjustments in addition to the PPFAC. The PPFAC adjustor Rate, as shown in the TEP Statement of Charges, is an amount expressed as a Rate per kWh charge to reflect the cost to the Company for energy either generated or purchased.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the ACC see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

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
This standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this Rider.

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 702
Superseding:

Rider R-2
Demand Side Management Surcharge (DSMS)

APPLICABILITY
The Demand Side Management Surcharge (DSMS) will be applied to all Customers taking Standard Offer service from the Company pursuant to the Arizona Corporation Commission (ACC) Decision No. XXXXX dated XXXXXX XX, 2013

RATE
The DSMS shall be applied to all monthly bills. The DSMS will be assessed on a per kWh basis for residential Customers and on a percentage of bill basis for non-residential Customers. The Rates are shown in the TEP Statement of Charges.

REQUIREMENTS
The 2013 TEP DSMS is effective XXXX, XX, 2013 and will remain in effect until further order by the ACC.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the ACC see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

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 ACC shall apply where not inconsistent with this Rider

Filed By:	Kentton C. Grant	Rate:	R-2
Title:	Vice President of Finance and Rates	*Effective:*	*PENDING*
District:	Entire Electric Service Area	Decision No.:	

DECISION NO. 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 703
Superseding:

Rider R-3
Market Cost of Comparable Conventional Generation (MCCCG) Calculation as Applicable to Rider-4 NM-PRS

AVAILABILITY

The Market Cost of Comparable Conventional Generation (MCCCG) calculation, Rider-3, is restricted solely to Rider-4, Net Metering for Certain Partial Requirements Service (NM-PRS). If for a billing month a Rider-4 NM-PRS Customer's generation facility's energy production exceeds the energy supplied by the Company, the Customer's bill for the next billing period shall be credited for the excess generation as described in Rider-4 NM-PRS. The excess kWh during the billing period shall be used to reduce the kWh supplied (not kW or kVA demand or customer/facilities charges) and billed by the Company during the following billing period. Each calendar year, for the customer bills produced in October (September usage) or a customer's "Final" bill - the Company shall credit the Customer for the positive balance of excess kWhs (if any) after netting against billing period usage. The payment for the purchase of the excess kWhs will be at the Company's applicable avoided cost, which for purposes of Rider-4 NM-PRS shall be the simple average of the hourly MCCCG as described below for the applicable year.

The Arizona Corporation Commission (ACC) provided guidance on defining MCCCG in the context of its REST Rules and identified the MCCCG as "the Affected Utility's energy and capacity cost of producing or procuring the incremental electricity that would be avoided by the resources used to meet the Annual Renewable Energy Requirement, taking into account hourly, seasonal and long term supply and demand circumstances. Avoided costs include any avoided transmission and distribution costs and any avoided environmental compliance costs." R14-2-1801.11.

CALCULATION/METHODOLOGY

For purposes of calculating credits to the Customer for Excess Generation, the unit price paid (Credit for Excess Generation) shall be the simple average of the MCCCG over the 8,760 hours (8,784 in a leap year) hours in the forecasted year. The MCCCG in each hour is based on whether native load requirements will be met by internally owned or contracted generation resources or if market purchases will be required to meet native load requirements. The following table provides a description of the MCCCG methodology. The hourly MCCCG cost determination criteria is based on the Market Condition and Dispatch Type. This method of cost determination is very data intensive and will be calculated annually by running TEP's "Planning and Risk" modeling software, and the rate will be filed with the Commission by February 1 of each year and its applicability will coincide with the next Purchased Power and Fuel Adjustment Clause ("PPFAC") rate effective period.

RATE

The customer monthly bill shall consist of the applicable Rate, charges and adjustments in addition to the Credit for Excess Generation based on the MCCCG. The MCCCG is an amount expressed as a rate per kWh charge that is approved by the ACC on or before April 1 of each year and effective with the first billing cycle in April, as shown in the TEP Statement of Charges.

TEP STATEMENT OF CHARGES

For all additional charges and assessments approved by the ACC see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

Filed By:	Kentton C. Grant	Rate:	R-3
Title:	Vice President of Finance and Rates	Effective:	PENDING
District:	Entire Electric Service Area	Decision No.:	

DECISION NO. 73912

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 703-1
Superseding:

MCCCG Cost Determination Matrix

Market Condition and Dispatch Type	Selling to Market from In House Real and Contracted Generation Sources	MCCCG Cost Based on Incremental Production/Purchase Cost of Base Load Generation for that *hour*
	No Market Transactions from/to In House and Contracted Generation Sources	
	Purchasing from Day Ahead Market, but not Spot Market, to meet Native Load Requirements	MCCCG Cost Based on Average Day Ahead Market Price of Purchased Power for that hour
	Purchasing from Spot Market to meet Native Load Requirements	MCCCG Cost Based on Average Spot Market Price of Purchased Power for that hour

Incremental Production / Purchase of Base Load - The cost of the next kWh (incremental) amount of load that has to be provided by TEP generation sources and/or purchased power. This will be dependent on the season, month and time of day.

If Day Ahead Market or Spot Market purchases are being used to provide for reliability support capacity to meet native load requirements by freeing up in house or contracted generation resources for regulation or spinning reserve purposes for support of native load requirements, that would still represent a Market Purchase for purposes of determining which matrix box is applicable.

Filed By:	Kentton C. Grant	Rate:	R-3
Title:	Vice President of Finance and Rates	Effective:	PENDING
District:	Entire Electric Service Area	Decision No.:	

DECISION NO. 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 704
Superseding:

Rider R-4
Net Metering for Certain
Partial Requirements Service (NM-PRS)

AVAILABILITY

Available throughout the Company's entire electric service area to any Customer with a facility for the production of electricity on its premises using Renewable Resources [1], a Fuel Cell [2] or Combined Heat and Power (CHP) [3] to generate electricity, which is operated by or on behalf of the Customer, is intended to provide all or part of the Customer's electricity requirements, has a generating capacity less than or equal to 125% of the Customer's total connected load at the metered premise, or in the absence of load data, has capacity less than the Customer's electric service drop capacity, and is interconnected with and can operate in parallel and in phase with the Company's existing distribution system. Customer shall comply with all applicable federal, state, and local laws, regulations, ordinances and codes governing the production and/or sale of electricity.

For purposes of this Rate, the following notes and/or definitions apply:

[1]Renewable Resources means natural resources that can be replenished by natural process. Renewable Resources include biogas, biomass, geothermal, hydroelectric, solar, or wind.

[2]Fuel Cell means a device that converts the chemical energy of a fuel directly into electricity without intermediate combustion or thermal cycles. The source of the chemical reaction must be derived from Renewable Resources.

[3]Combined Heat and Power (CHP) also known as cogeneration means a system that generates electricity and useful thermal energy in a single integrated system such that the useful power output of the facility plus one-half the useful thermal energy output during any 12-month period must be no less than 42.5 percent of the total energy input of fuel to the facility.

CHARACTER OF SERVICE

The service shall be single- or three-phase, 60 Hertz, at one standard nominal voltage as mutually agreed and subject to availability at the point of delivery. Primary metering will be used by mutual agreement between the Company and the Customer.

RATE

Customer Charges shall be billed pursuant to the Customer's standard offer Rate otherwise applicable under full requirements of service.

Power sales and special services supplied by the Company to the Customer in order to meet the Customer's supplemental or interruptible electric requirements will be priced pursuant to the Customer's standard offer Rate otherwise applicable under full requirements service.

Non-Time-of-Use Rates: For Customers taking service under a Standard Retail Rate that is not a time-of-use rate, the Customer Supplied kWh shall be credited against the Company Supplied kWh. The Customer's monthly bill shall be based on this net kWh amount. Any monthly Excess Generation will be treated in accordance with the provisions outlined below.

Time-of-Use Rates: For Customers taking service under a Standard Retail Rate that is a time-of-use rate, the Customer Supplied kWh during on-peak hours shall be credited against the Company Supplied kWh during on-peak hours. All Customer Supplied kWh during off-peak hours shall be credited against the Company Supplied kWh during off-peak hours. The Customer's monthly bill shall be based on this net kWh amount. Any monthly Excess Generation will be treated in accordance with the provisions outlined below.

EXCESS GENERATION
If for a billing month the Customer's generation facility's energy production exceeds the energy supplied by the Company, the Customer's bill for the next billing period shall be credited for the excess generation. That is, the excess kWh during the billing period shall be used to reduce the kWh supplied (not kW or kVA demand or customer/facilities charges) and billed by the Company during the following billing period. Customers taking service under a time-of-use rate who are to receive credit in a subsequent billing period for excess kWh generated shall receive such credit in the next billing period for the on-peak or off-peak periods in which the kWh were generated by the Customer. Time-of-Use Customer's taking service in the billing month of April shall receive a credit to summer on-peak and summer off-peak usage in the billing month of May for any winter on-peak and/or winter off-peak excess generation for April.

Each calendar year, for the customer bills produced in October (September usage) or a customer's "Final" bill - the Company shall credit the Customer for the balance of excess kWhs after netting. The payment for the purchase of the excess kWhs will be at the Company's applicable avoided cost, which for purposes of this rate shall be the simple average of the hourly Market Cost of Comparable Conventional Generation (MCCCG) Rider-3 for the applicable year. The MCCCG, as it applies to this rate, is specified in Rider-3 MCCCG - Market Cost of Comparable Conventional Generation (MCCCG) Calculation as Applicable to Rider-4 NM-PRS (Net Metering for Certain Partial Requirements Service).

METERING
The Company will install a bi-directional meter at the point of delivery to the customer and meter at the point of output from each of the Customer's generators. At the Company's request a dedicated phone line will be provided by the customer to the metering to allow remote interegation of the meters at each site. If by mutal agreement between company and customer that a phone line is impractical or can not be provided - the customer will work with company to allow for the installation of equipment, on or with customer facilities or equipment to allow remote acces to each meter. Any additional cost of communication, such as but not limited too, cell phone service fees will be the responsibility of the customer.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

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 ACC shall apply where not inconsistent with this Rider.

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 705
Superseding:

Rider R-5
Electric Service Solar Rider
(Bright Tucson Community Solar™)

APPLICABILITY

Rider-5 is for individually metered Customers who wish to participate in the Bright Tucson Community Solar Program. Under Rider-5, Customers will be able to purchase blocks of electricity from solar generation sources. Participation in Rider-5 is limited in the Company's sole discretion to the amount of solar generation available and subscription will be made on a first come, first served basis. In order to maximize subscription under Rider-5, TEP may limit the amount of solar block energy purchased by individual Customers. Rider-5 available prior to XXXXXX XX, 2013 is further restricted to Customers being served under one of the following Rates:

1) Residential Lifeline Discount, Rate R-06-01
2) Residential Electric Service, Rate R-01
3) Small General Service, Rate GS-10
4) Large General Service, Rate LGS-13
5) Municipal Service, Rate PS-40

Rider-5 effective XXXXXX XX, 2013 is further restricted to Customers being served under one of the following Rates:

1) Residential Electric Service, Rate R-01
2) Small General Service, Rate GS-10
3) Large General Service, Rate LGS-13

Customers being served under self-generation riders or plans may not purchase power under Rider-5 (including, but not limited to Net Metering for Certain Partial Requirements Service Rider-4 and Non-Firm Power Purchase from Renewable Energy Resources and Qualifying Cogeneration Facilities of 100 kilowatts (kW) or Less Capacity Rider-101).

RATE

Customers can contract for a portion or up to their average annual usage in solar blocks of 150 kilowatt hours (kWh) each. Transmission and distribution charges will be applied to all energy delivered, including energy delivered under Rider-5. The Customer is responsible for paying (each month) all charges incurred under their applicable rate schedule, and the total solar energy contracted for multiplied by the applicable solar block energy rate. Any demand based charges under the Customer's current Rate will not be affected by elections under Rider-5.

TEP STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rate.

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.

TERMS AND CONDITIONS

1) Customers may contract for a portion or up to their average annual usage in solar blocks of 150 kWh. If Customer's annual average usage is not available, TEP will apply the appropriate class average. This limit can be reviewed annually at the request of the Customer.

2) Each solar block's energy rate will be maintained for twenty years from the date of purchase. For the purposes of the twenty year energy rate, solar blocks will be attributed to the Customer's original service address. Transfer of service under Rider-5 is prohibited. Should the Customer cancel service for any reason, his or her subscription under Rider-5 will expire.

3) Customers may add or delete solar blocks once within a twelve month period. Any addition of solar blocks will be at the then offered solar block energy rate.

4) Solar blocks will be applied to the actual energy usage each month. Electricity used in excess of the purchased solar blocks will be billed at the Customer's regular energy rate. If electricity usage is below the amount covered by the solar block(s), then the excess kWhs will be rolled forward and credited again the Customer's usage in the following month. The Customer will still be responsible for the full cost of the block(s) each month.

   Customers will be credited for the balance of any excess kWhs annually, or on their final bill should the Customer terminate service under Rider-5. Each year, for the bills produced in October (September usage), TEP will credit Customers their excess kWhs after netting and reset their balance to zero. Credit for excess kWhs will be at the energy rate of the oldest solar block.

5) All contracted solar block kWhs and associated charges in a billing month will be excluded from the calculation of PPFAC and REST charges and/or credits.

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 706
Superseding:

Rider R-6
Renewable Energy Standard and Tariff (REST) Surcharge
REST-TS1 Renewable Energy Program Expense Recovery

APPLICABILITY
Mandatory, non-bypassable surcharge applied to all energy consumed by all Customers throughout Company's entire electric service area.

RATES
For all energy billed which is supplied by the Company to the Customer. The REST surcharge shall be applied to all monthly bills. The REST rates are shown in the TEP Statement of Charges.

Notes:

1) A Large Commercial Customer is one with monthly demand greater or equal to 200 kW but less than 3,000 kW.
2) An Industrial Customer is one with monthly demand equal to or greater than 3,000 kW.
3) For non-metered services, the lesser of the load profile or otherwise estimated kWh required to provide the service in question, or the service's contract
4) kWh shall be used in the calculation of the surcharge.

This charge will be a line item on customer bills reading "Renewable Energy Standard Tariff."

Per Decision No. 73637 effective February 1, 2013, any Customer who has received incentives under the REST Rules, shall pay the average of the REST surcharge paid by members of their Customer class. This requirement shall apply to renewable systems reserved on and after January 1, 2012. The average price by class is shown in the TEP Statement of Charges

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this Rider.

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.

Filed By:	Kentton C. Grant	Rate:	R-6
Title:	Vice President of Finance and Rates	Effective:	PENDING
District:	Entire Electric Service Area	Decision No.:	

DECISION NO. 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 707
Superseding:

Rider R-7
Customer Self-Directed Renewable Energy Option
REST-TS2 Renewable Energy Standard Tariff

AVAILABILITY
Open to all Eligible Customers as defined at A.A.C. R14-02-1801.H.

APPLICABILITY
Any Eligible Customer that applies to the Company under this program and receives approval shall participate at its option.

PARTICIPATION PROCESS
An Eligible Customer seeking to participate shall submit to the Company a written application that describes the Distributed Renewable Energy (DRE) resources or facilities that it proposes to install and the estimated costs of the project. The Company shall have sixty (60) calendar days to evaluate and respond in writing to the Eligible Customer, either accepting or declining the project. If accepted, the Customer shall be reimbursed up to the actual dollar amounts of customer surcharge paid under the REST-TS1 Tariff in any calendar year in which DRE facilities are installed as part of the accepted project. To qualify for such funds, the Customer shall provide at least half of the funding necessary to complete the project described in the accepted application, and shall provide the Company with sufficient and reasonable written documentation of the project's costs. Customer shall submit their application prior to May 1 of a given year to apply for funding in the following calendar year.

FACILITIES INSTALLED
The maintenance and repair of the facilities installed by a Customer under this program shall be the responsibility of the Customer following completion of the project. In order to be accepted by the Company for reimbursement purposes, the project shall, at a minimum, conform to the Company's System Qualification standards on file with the Commission. (REST Implementation Plan, Renewable Energy Credit Purchase Program – RECPP, Distributed Generation Interconnection Requirements, Net Metering Tariff, Company's Interconnection Manual)

PAYMENTS AND CREDITS
All funds reimbursed by the Company to the Customer for installation of approved DRE facilities shall be paid on an annual basis no later than March 30th of each calendar year. All Renewable Energy Credits derived from a project, including generation and Extra Credit Multipliers, shall become the property of the Company and shall be applied towards the Company's Annual Renewable Energy Requirement as defined in A.A.C. R14-2-1801.B.

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 Rider.

RELATED SCHEDULES

- REST-TS1 - Renewable Energy Program Expense Recovery

TEP
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Original Sheet No.: 708
Superseding:

Rider R-8
Lost Fixed Cost Recovery (LFCR)

APPLICABILITY
The Lost Fixed Cost Recovery (LFCR) will be applied to all Customers taking service from the Company other than traffic signal and street lighting service, lighting service, water pumping service, and large light and power service as defined in the Company's LFCR Plan of Administration (POA). As provided for in the POA, in the event a residential Customer chooses to contribute to this program by paying a fixed charge option, the monthly Customer Charge specified on the appropriate Standard Offer tariff will be charged in lieu of the percentage rate shown in the TEP Statement of Charges.

CHANGE IN RATE
The LFCR recovers a portion of the authorized margin approved in the Company's most recent rate case that has been lost as the result of implementing ACC-mandated Energy Efficiency and Distributed Generation programs. Each year, a percentage charge will be placed in effect and charged to the participating Rate classes for the 12-month period the LFCR adjustment is applicable. The total year-on-year adjustment cannot exceed 2% of the Company's most recent total combined retail calendar year revenues for all participating Rate classes.

The LFCR adjustment shall be applied to all monthly bills as a percentage of the total bill and is anticipated to become effective on or around July 1, 2014.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

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 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 ACC shall apply where not inconsistent with this rate.

Filed By:	Kentton C. Grant	Rate:	R-8
Title:	Vice President of Finance and Rates	Effective:	PENDING
District:	Entire Electric Service Area	Decision No.:	

DECISION NO. 73912

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 709
Superseding:

Rider R-9
Environmental Compliance Adjustor (ECA)

APPLICABILITY
The Environmental Compliance Adjustor (ECA) will be applied to all Customers taking Standard Offer service from the Company pursuant to the Arizona Corporation Commission (ACC) Decision No. XXXX dated XXX, 2013 and as defined in the Company's ECA Plan of Administration.

RATE
The Customer monthly bill shall consist of the applicable Rate charges and adjustments including the ECA. The ECA adjustor Rate is an amount expressed as a Rate per kWh charge, as shown in the TEP Statement of Charges.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the ACC see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

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
This standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this Rider.

Filed By:	Kentton C. Grant	Rate:	R-9
Title:	Vice President of Finance and Rates	Effective:	PENDING
District:	Entire Electric Service Area	Decision No.:	

DECISION NO. 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 710
Superseding:

Rider R-10
MGC-1 Market Generation Credit (MGC) Calculation

INTRODUCTION
There are two purposes of the Market Generation Credit (MGC). The first purpose is to establish a price to which TEP's energy customers can compare to the prices of competitors. The second purpose is to enable the calculation of the variable or "floating" component of TEP's stranded cost recovery. Shown below are the terms of the MGC methodology per TEP's Settlement Agreement, Section 2.1(d), as amended March 20, 2003:

> The monthly MGC amount shall be calculated in advance and stated as both an on-peak value and an off-peak value. The monthly on-peak MGC component shall be equal to the Market Price multiplied by one plus the appropriate line loss (including unaccounted for energy ("UFE")) amount. The Market Price shall be equal to the Tullett Liberty Long-Term Forward Assessment for the Palo Verde Forward price, except when adjusted for the variable cost of TEP's must-run generation. The Market Price shall be determined thirty (30) days prior to each calendar month using the average of the most recent three (3) business days of Tullett Liberty Long-Term Forward Assessment for Palo Verde settlement prices. The off-peak MGC component shall be determined in the same manner as the on-peak component, except that the Tullett Liberty Long-Term Forward Assessment for the Palo Verde Forward price will be adjusted by the ratio of off-peak to on-peak prices from the Dow Jones Palo Verde Index of the same month from the preceding year. The MGC shall be equal to the hours-weighted average of the on-peak and off-peak pricing components and shall reflect the cost of serving a one hundred percent (100%) load factor customer.

To reflect the cost of serving a 100% load factor customer, the actual MGC used for billing calculations will be a loss adjusted average price that is weighted by the ratio of on-peak and off-peak hours. This process is illustrated in equations 4 and 5 below and will be posted to TEP's website http://partners.tucsonelectric.com thirty (30) days prior to each calendar month. This composite price will be credited to all energy consumption, regardless of the time period in which it is consumed.

CALCULATIONS
Five steps are outlined below for the calculation of the MGC. None of the steps are excludable for any customer type. Acronyms are defined in the Glossary at the end of this document.

1. **Calculating the on-peak MGC**

Thirty (30) days prior to each calendar estimation month, the Tullet Prebon Long-Term Forward Assessment for Palo Verde Forward prices for the three (3) most recent business days are used. The simple average (or arithmetic mean) is calculated for these three (3) days for the estimation month.

$$MGC_{ON,t} = \frac{\sum (TULLETT)_i}{3} \qquad \text{(Equation 1)}$$

The calculation is illustrated in the table below.

Forward Prices per MWh	Apr-2002
3/1/2002	$25.50
2/28/2002	$25.50
2/27/2002	$24.75
Average	$25.25

2. Calculating the off-peak MGC

The off-peak MGC is determined by multiplying the on-peak MGC value by the off-peak price weighting factor (WEIGHT). The WEIGHT is equal to the simple average of all off-peak prices from the Dow Jones Palo Verde Index in the same month of the previous year, divided by the simple average of all on-peak prices from the Dow Jones Palo Verde Index in the same month of the previous year. Off-peak, on-peak and holiday hours are defined by NERC in the estimation month.

$$MGC_{OFF,i} = MGC_{ON,i} * WEIGHT_i \qquad \text{(Equation 2)}$$

where

$$WEIGHT_i = \frac{DJPVI_{OFF,i}}{DJPVI_{ON,i}} \qquad \text{(Equation 3)}$$

3. Weighting the MGC for hours in the month

The on-peak and off-peak MGCs are combined to form an average MGC by computing a weighted average of the two time periods. This is done by multiplying the on-peak MGC by the percentage of on-peak hours in the same month of the previous year and then adding the product of the off-peak MGC and the percentage of off-peak hours in the same month of the previous year. Off-peak, on-peak and holiday hours are defined by NERC in the estimation month.

$$MGC_{WEIGHT,i} = MGC_{ON,i} * \left(\frac{ONHOURS}{ONHOURS + OFFHOURS} \right) + MGC_{OFF,i} * \left(\frac{OFFHOURS}{ONHOURS + OFFHOURS} \right)$$

(Equation 4)

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Superseding:

4. **Loss-adjusting the MGC**

The average MGC must be adjusted for line losses. The appropriate line loss adjustment factor (LLAF) for a large industrial customer is 1.0515. For all other customers, the appropriate factor is 1.0919.

$$MGC_{LOSS,i} = MGC_{WEIGHT,i} * LLAF \qquad \text{(Equation 5)}$$

5. **Adjusting the MGC for variable must-run**

The MGC will be adjusted for variable must-run as defined in TEP's Stranded Cost Settlement Agreement and AISA protocols. Fifteen (15) days prior to each month, TEP forecasts a ratio of its variable must-run generation to retail system demand for the following month. The MGC is determined by adding the product of MGC_{LOSS} and one minus the ratio of variable must-run generation to total retail system demand to the product of $15/MWh and the variable must-run ratio.

$$MGC_i = [MGC_{LOSS,i} * (1 - VMR_i)] + (\$15 * VMR_i) \qquad \text{(Equation 6)}$$

This calculation produces the final value for the Market Generation Credit.

GLOSSARY

$DJPVI_{OFF}$	Simple average of off-peak prices on the Dow Jones Palo Verde Index.
$DJPVI_{ON}$	Simple average of on-peak prices on the Dow Jones Palo Verde Index.
Dow Jones Palo Verde Index	Daily calculation of actual firm on-peak and firm off-peak weighted average prices for electricity traded at Palo Verde, Arizona switchyard.
AISA	Arizona Independent Scheduling Administrator, a temporary entity, independent of transmission-owning organizations, intended to facilitate nondiscriminatory retail direct access using the transmission system in Arizona. Required by the Arizona Corporation Commission Retail Electric Competition Rules.
LLAF	Line-loss adjustment factor.
MGC	Market Generation Credit.
MGC_{OFF}	MGC_{ON} weighted by the ratio of off-peak to on-peak prices on the Dow Jones Palo Verde Index.
MGC_{ON}	Average of the Tullett Liberty prices on days appropriate for the calculation of the MGC.

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Original Sheet No.: 710-3
Superseding:

MGC_{LOSS}	MGC_{WEIGHT} adjusted for line losses (including unaccounted for energy) on TEP's generation and energy delivery systems.
MGC_{WEIGHT}	A weighted average of MGC_{ON} and MGC_{OFF} by ONHOURS and OFFHOURS.
Must-run Generation	The cost associated with the running of local generating units needed to maintain distribution system reliability and to meet load requirements in times of congestion on certain portions of the interconnected grid.
NERC	North American Electric Reliability Council. A voluntary not-for-profit organization established to promote bulk electric system reliability and security. Membership includes: investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers.
OFFHOURS	Number of total monthly off-peak hours as defined by NERC. Off-peak hours are hour ending 0100 – hour ending 0600 and hour ending 2300 – hour ending 2400, Monday through Saturday, Pacific Prevailing Time (PPT). All Sunday hours are considered off-peak. PPT is defined as the current clock time in the Pacific time zone.
ONHOURS	Number of total monthly on-peak hours as defined by NERC. On-peak hours are hour ending 0700 – hour ending 2200 Monday through Saturday, Pacific Prevailing Time (PPT). PPT is defined as the current clock time in the Pacific time zone.
TULLETT	Tullett Liberty - a provider of independent real-time price information from the wholesale inter-dealer brokered commodity markets, from which the on-peak Long Term Forward Assessment of market prices of electricity at the Palo Verde, Arizona switchyard are obtained. The forward product is "6 x 16," power is for 16 hours a day for six days a week (Monday through Saturday) for the delivery period, excluding NERC holidays.
Stranded Costs	The difference between revenues under competition and the costs of providing service, *including the inherited fixed costs from the previous regulated market.*
TEP	Tucson Electric Power Company, a subsidiary of UNS Energy Corp.
TEP Settlement Agreement	An agreement between TEP, the Arizona Residential Utility Consumer Office, members of the Arizonans for Electric Choice and Competition, and Arizona Community Action Association regarding TEP's implementation of retail electric competition, implementation of unbundled tariffs, and recovery of stranded costs.
VMR	Ratio of variable must-run generation (MW) to total retail system demand (MW) in TEP's service territory.
WEIGHT	Ratio of off-peak to on-peak prices on the Dow Jones Palo Verde Index.

Filed By:	Kentton C. Grant	Rate:	R-10
Title:	Vice President of Finance and Rates	Effective:	Pending
District:	Entire Electric Service Area	Decision No.:	

DECISION NO. 73912

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 711
Superseding:

Rider R-11
Schedule MGC-2 Market Generation Credit (MGC)
Calculation for Partial Requirements Services

INTRODUCTION
The purpose of the Market Generation Credit (MGC) for Partial Requirements Services is to establish a price at which TEP's partial requirements customers will purchase backup/standby and supplemental energy for applicable Partial Requirements Service tariff customers. The Market Generation Credit for Partial Requirements Services is consistent with the MGC methodology per TEP's Settlement Agreement, Section 2.1(d), as amended March 20, 2003.

The monthly MGC amount shall be calculated in advance and stated as both an on-peak value and an off-peak value. The monthly on-peak MGC component shall be equal to the Market Price multiplied by one plus the appropriate line loss (including unaccounted for energy ("UFE")) amount. The Market Price shall be equal to the Tullett Liberty Long-Term Forward Assessment for the Palo Verde Forward price, except when adjusted for the variable cost of TEP's must-run generation. The Market Price shall be determined fifteen (15) days prior to each calendar month using the average of the most recent three (3) business days of Tullett Liberty Long-Term Forward Assessment for Palo Verde settlement prices. The off-peak MGC component shall be determined in the same manner as the on-peak component, except that the Tullett Liberty Long-Term Forward Assessment for the Palo Verde Forward price will be adjusted by the ratio of off-peak to on-peak prices from the Dow Jones Palo Verde Index of the same month from the preceding year.

CALCULATIONS.
The Customer will be charged adjusted on-peak MGC multiplied by kWh consumption for On-peak hours, and adjusted off-peak MCG multiplied by kWh consumption for Off-peak hours. Three steps are outlined below for the calculation of the MGC. None of the steps are excludable for any customer type. Acronyms are defined in the Glossary at the end of this document.

1. **Calculating the on-peak MGC**

Fifteen (15) days prior to each calendar estimation month, the Platts Long-Term Forward Assessment for Palo Verde Forward prices for the three (3) most recent business days are used. The simple average (or arithmetic mean) is calculated for these three (3) days for the estimation month.

$$MGC_{ON,i} = \frac{\sum (TULLETT)_i}{3} \qquad \text{(Equation 1)}$$

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The calculation is illustrated in the table below.

Forward Prices per MWh	Apr 2002
3/13/2002	$25.80
3/14/2002	$26.90
3/15/2002	$27.75
Average	$26.82

2. Calculating the off-peak MGC

The off-peak MGC is determined by multiplying the on-peak MGC value by the off-peak price weighting factor (WEIGHT). The WEIGHT is equal to the simple average of all off-peak prices from the Dow Jones Palo Verde Index in the same month of the previous year, divided by the simple average of all on-peak prices from the Dow Jones Palo Verde Index in the same month of the previous year. Off-peak, on-peak and holiday hours are defined by NERC in the estimation month.

$$MGC_{OFF,i} = MGC_{ON,i} * WEIGHT_i \qquad \text{(Equation 2)}$$

where

$$WEIGHT_i = \frac{DJPVI_{OFF,i}}{DJPVI_{ON,i}} \qquad \text{(Equation 3)}$$

3. Loss-adjusting the MGC

The on-peak MGC and the off-peak MGC must be adjusted for line losses. The appropriate line loss adjustment factor (LLAF) for the large industrial customer class is 1.0515; for all other customer classes, the appropriate factor is 1.0919.

$$MGC_{LOSS-ON,i} = MGC_{ON,i} * LLAF \qquad \text{(Equation 4)}$$

$$MGC_{LOSS-OFF,i} = MGC_{OFF,i} * LLAF \qquad \text{(Equation 5)}$$

This calculation produces the final value for the on-peak and off-peak Market Generation Credits.

GLOSSARY

$DJPVI_{OFF}$	Simple average of off-peak prices on the Dow Jones Palo Verde Index.
$DJPVI_{ON}$	Simple average of on-peak prices on the Dow Jones Palo Verde Index.
Dow Jones Palo Verde Index	Daily calculation of actual firm on-peak and firm off-peak weighted average prices for electricity traded at Palo Verde, Arizona switchyard.

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Original Sheet No.: 711-2
Superseding:

LLAF	Line-loss adjustment factor.
MGC	Market Generation Credit.
MGC_{OFF}	MGC_{ON} weighted by the ratio of off-peak to on-peak prices on the Dow Jones Palo Verde Index.
MGC_{ON}	Average of the Tullett Liberty prices on days appropriate for the calculation of the MGC.
$MGC_{LOSS\text{-}ON}$	MGC_{ON} adjusted for line losses (including unaccounted for energy) on TEP's generation and energy delivery systems.
$MGC_{LOSS\text{-}OFF}$	MGC_{OFF} adjusted for line losses (including unaccounted for energy) on TEP's generation and energy delivery systems.
NERC	North American Electric Reliability Council. A voluntary not-for-profit organization established to promote bulk electric system reliability and security. Membership include investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers.
Off-Peak Hours	Number of total monthly off-peak hours as defined by NERC. Off-peak hours are hour ending 0100 – hour ending 0600 and hour ending 2300 – hour ending 2400, Monday through Saturday, Pacific Prevailing Time (PPT). All Sunday hours are considered off-peak. PPT is defined as the current clock time in the Pacific time zone.
On-Peak Hours	Number of total monthly on-peak hours as defined by NERC. On-peak hours are hour ending 0700 – hour ending 2200 Monday through Saturday, Pacific Prevailing Time (PPT). PPT is defined as the current clock time in the Pacific time zone.
TULLETT	Tullett Liberty - a provider of independent real-time price information from the wholesale inter-dealer brokered commodity markets, from which the on-peak Long Term Forward Assessment of market prices of electricity at the Palo Verde, Arizona switchyard are obtained. The forward product is "6 x 16," power is for 16 hours a day for six days a week (Monday through Saturday) for the delivery period, excluding NERC holidays.
Stranded Costs	The difference between revenues under competition and the costs of providing service, including the inherited fixed costs from the previous regulated market.
TEP	Tucson Electric Power Company, a subsidiary of UNS Energy Corp.
TEP Settlement Agreement	An agreement between TEP, the Arizona Residential Utility Consumer Office, members of the Arizonans for Electric Choice and Competition, and Arizona Community Action Association regarding TEP's implementation of retail electric competition, implementation of unbundled tariffs, and recovery of stranded costs.
WEIGHT	Ratio of off-peak to on-peak prices on the Dow Jones Palo Verde Index.

TEP
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Original Sheet No.: 802
Superseding:

Bill Estimation Methodologies

Tucson Electric Power Company (TEP) regularly encounters situations in which TEP cannot obtain a complete and valid meter read. No matter the cause of the need to estimate the read, the following methods are used depending on the circumstances.

PREVIOUS YEAR FORMULA

SAME CUSTOMER WITH AT LEAST ONE YEAR OF HISTORY

TEP would generate a bill based on customer usage from the previous year using the "PREVIOUS YEAR" formula as follows:

If last year's usage was estimated, see Previous Month Formula:

LAST YEAR'S USAGE FOR SAME MONTH / NUMBER OF DAYS IN BILLING PERIOD ■ PER DAY USAGE
(FOR "TIME OF USE" (TOU) THIS WOULD BE APPLIED TO EACH PERIOD)

PER DAY USAGE X NUMBER OF DAYS IN THIS MONTH'S CYCLE = ESTIMATED USAGE
(FOR TOU THIS WOULD BE APPLIED TO EACH PERIOD)

PREVIOUS MONTH FORMULA

SAME CUSTOMER AT SAME PREMISE WITH LESS THAN ONE YEAR OF HISTORY

TEP would generate a bill based on customer usage from the previous month using the "PREVIOUS MONTH" formula as follows:

If last month's usage was estimated, see Trend Formula:

LAST MONTHS USAGE / NUMBER OF DAYS IN BILLING PERIOD = PER DAY USAGE
(FOR TOU THIS WOULD BE APPLIED TO EACH PERIOD)
PER DAY USAGE X NUMBER OF DAYS IN THIS MONTH'S CYCLE = ESTIMATED USAGE
(FOR TOU THIS WOULD BE APPLIED TO EACH PERIOD)

TREND FORMULA

NEW CUSTOMER AT SAME PREMISE

TEP would generate a bill using the "TREND" formula, based on customer's usage trend as described below:

TEP's customer information system (CIS) would generate a bill based on trend. Customers are assigned to a Trend area which differentiate consumption based on different geographic areas. Secondly, the customer is assigned to a Trend class which is used to differentiate consumption trends based on the type of service and type of property. An example of this would be residential, commercial, and industrial usage. Thirdly, all consumption is identified using unit of measure code and a time of use code. Within TEP's CIS, a trend record is created from each billed service. This record becomes part of a trend table. During estimation, consumption from three prior bill cycles is compared to the consumption from the same cycle in the previous month to determine a trend. This trend, plus a tolerance, is used to create a usage amount for bill estimation.

CUSTOMER'S USAGE IN PREVIOUS PERIOD/ AVERAGE CUSTOMER'S USAGE IN PREVIOUS PERIOD X AVERAGE CUSTOMER'S USAGE IN CURRENT PERIOD = ESTIMATED CONSUMPTION FOR REGISTER READ

NO HISTORY

TEP would not generate a bill until a good meter read was acquired then use known consumption to estimate previous bills.

Filed By:	Kentton C. Grant	Rate:	Bill Estimation - 1
Title:	Vice President of Finance and Rates	Effective:	Pending
District:	Entire Electric Service Area	Decision No.:	

DECISION NO. 73912

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Original Sheet No.: 802-1
Superseding:

Demand Estimate

For accounts that have a demand billing component TEP collects interval data. This interval data is used to manually estimate demands using the following methodologies:

SAME CUSTOMER AT SAME PREMISE WITH AT LEAST ONE YEAR OF HISTORY
TEP would generate a bill based on customer usage from the previous year using the following formula:

LAST YEAR'S DEMAND FOR SAME MONTH = ESTIMATED DEMAND

NEW CUSTOMER AT SAME PREMISE WITH AT LEAST ONE YEAR OF HISTORY
TEP would generate a bill based on customer usage from the previous month using the following formula:

LAST MONTHS DEMAND = ESTIMATED DEMAND

SAME CUSTOMER AT SAME PREMISE WITH LESS THAN ONE YEAR OF HISTORY
TEP would generate a bill based on customer usage from the previous month using the following formula:

LAST MONTHS DEMAND = ESTIMATED DEMAND

NEW CUSTOMER AT SAME PREMISE WITH LESS THAN ONE YEAR OF HISTORY
TEP would generate a bill based on customer usage from the previous month using the following formula:

LAST MONTHS DEMAND = ESTIMATED DEMAND

NO HISTORY
TEP would not generate a bill until a good demand read was acquired then use known demand to estimate previous bills.

ATTACHMENT "K"

TEP
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Original Sheet No.: 801

Superseding:

TEP STATEMENT OF CHARGES

Fee No.	Description	Rate	Effective Date	Decision No.
1.	Service Transfer Fee	$ 20.00	PENDING	PENDING
2.	Customer-Requested Meter Re-read	$ 20.00	PENDING	PENDING
3.	Special Meter Reading Fee	$ 20.00	PENDING	PENDING
4.	Automated Meter Opt-Out Meter Change-Out Fee	$ 20.00	PENDING	PENDING
5.	Additional Customer Charge for Automated Meter-Opt Out Customers	$ 10.00	PENDING	PENDING
6.	Additional Customer Charge for Self-Read Automated Meter Opt-Out Customers	$ 5.00	PENDING	PENDING
7.	Service Establishment and Reestablishment under usual operating procedures During Regulator Business Hours – Single-Phase Service	$ 32.00	PENDING	PENDING
8.	Service Establishment and Reestablishment under usual operating procedures After Regular Business Hours (includes Saturdays, Sundays and Holidays) – Single Phase Service	$ 57.00	PENDING	PENDING
9.	Service Establishment and Reestablishment under usual operating procedures During Regular Business Hours – Three-Phase Service	$ 78.00	PENDING	PENDING
10.	Service Establishment and Reestablishment under usual operating procedures After Regular Business Hours (includes Saturdays, Sundays and Holidays) – Three-Phase Service	$ 216.00	PENDING	PENDING
11.	Service Reestablishment under other than usual operating procedures – Single-Phase Service	$ 150.00	PENDING	PENDING
12.	Single-Phase Line Extension Charge per Foot	$ 17.00	PENDING	PENDING
13.	Three-Phase Line Extension Charge per Foot	$ 27.00	PENDING	PENDING
14.	Underground Differential Line Extension Charge per Foot	$ 21.00	PENDING	PENDING
15.	PME Switchgear Cabinet	$20,500.00	PENDING	PENDING
16.	Meter Test	$ 186.00	PENDING	PENDING
17.	Returned Payment Fee	$ 10.00	PENDING	PENDING
18.	Late Payment Finance Charge	1.5%	PENDING	PENDING

Filed By: Kentton C. Grant
Title: Vice President of Finance and Rates
District: Entire Electric Service Area

Rate: Statement of Charges
Effective: Pending
Decision No.:

DECISION NO. 73912

TEP
Tucson Electric Power

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Original Sheet No.: 801-1

Superseding: ______

TEP STATEMENT OF CHARGES
(continued)

Description	Rate	Effective Date	Decision No.
Rider R-1 – Purchased Power and Fuel Adjustment Clause (PPFAC)	$(0.001388) per kWh	PENDING	PENDING
Rider R-2 – Demand Side Management Surcharge (DSMS) RESIDENTIAL: Effective Date of Order – June 2014 (or until the next DSMS ACC Decision) NON-RESIDENTIAL: Effective Date of Order – June 2014 (or until the next DSMS ACC Decision)	 $0.000443 per kWh 0.5033%	PENDING	PENDING
Rider R-3 – Market Cost of Comparable Conventional Generation (MCCCG) Calculation as Applicable to Rider-4 NM-PRS	$0.025854 per kWh	April 5, 2012	73085
Rider R-5 – Electric Service Solar Rider (Bright Tucson Community Solar™) Solar Block Energy Rate for Residential Lifeline Discount, Rate R-06-01 Solar Block Energy Rate for Residential Electric Service, Rate R-01 Solar Block Energy Rate for General Service, Rate GS-10 Solar Block Energy Rate for Large General Service, Rate LGS-13 Solar Block Energy Rate for Municipal Service, Rate PS-40	 $0.050198 per kWh $0.050324 per kWh $0.048475 per kWh $0.049371 per kWh $0.049086 per kWh	February 1, 2011	71835*
Rider R-5 – Electric Service Solar Rider (Bright Tucson Community Solar™) Solar Block Energy Rate for Residential Electric Service, Rate R-01 Solar Block Energy Rate for Small General Service, Rate GS-10 Solar Block Energy Rate for Large General Service, Rate LGS-13	 $0.053463 per kWh $0.053274 per kWh $0.053227 per kWh	PENDING	PENDING
Rider R-6 – Renewable Energy Standard and Tariff Surcharge REST-TS1 Renewable Energy Program Expense Recovery Monthly Cap For Residential Customers: For Small Commercial Customers: For Large Commercial Customers: For Industrial Customers: For Public Authority: For Lighting:	$0.008000 per kWh Monthly Cap $ 3.80 per month $ 130.00 per month $1,050.00 per month $7,700.00 per month $ 170.00 per month $ 130.00 per month	February 1, 2013	73637

*The Rider R-5 approved by Decision No. 71835 is closed for new enrollment as of XXXXX XX, 2013

Filed By:	Kentton C. Grant	Rate:	Statement of Charges
Title:	Vice President of Finance and Rates	Effective:	Pending
District:	Entire Electric Service Area	Decision No.:	

DECISION NO. 73912

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 801-2

Superseding:

TEP STATEMENT OF CHARGES
(continued)

Description	Rate	Effective Date	Decision No.
Rider R-6 – Renewable Energy Standard and Tariff Surcharge REST-TS1 Renewable Energy Program Expense Recovery Customers receiving REST incentives since January 1, 2012 are charged the following average cap (in place of a $ per kWh surcharge) Monthly Cap For Residential Customers: For Small Commercial Customers: For Large Commercial Customers: For Industrial Customers: For Public Authority: For Lighting:	Monthly Cap $ 3.21 per month $ 24.10 per month $ 797.05 per month $7,283.00 per month $ 53.50 per month $ 12.03 per month	February 1, 2013	73637
Rider R-8 – Lost Fixed Cost Recovery (LFCR) Mechanism	XXXXX %	On or around July 2014	PENDING
Rider R-9 – Environmental Compliance Adjustor (ECA)	$0.0000 per kWh	PENDING	PENDING

ATTACHMENT "L"

ATTACHMENT L

LIST OF MODIFIED OR ELIMINATED REPORTING REQUIREMENTS

1. Eliminating the requirement from Decision No. 56526 (June 22, 1989) that TEP file monthly reports on the unit performance for each generation unit, other sources of energy, costs for each generating unit, costs of other sources of energy and disposition of energy.

2. Eliminating the requirement from Decision Nos. 57029 (July 18, 1990) and 57924 (July 2, 1992) that TEP file annual reports covering the period from July 1 through June 30 of each year required by regarding an agreement with Liquid Air.

3. Modifying the Lifeline Discount Tariff reporting requirements from Decision No. 56659 (October 24, 1989) (as modified in Decision Nos. 56781, 56819, and 57370) to now require TEP to submit the following information on an annual basis: (i) The total number of participating customers receiving a discount; (ii) The total number of kWh consumed by customers receiving the discount; and (iii) The total dollar amount of discounts provided.