Docket No. E-7, Sub 1146

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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

Arizona Corporation Commission
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TOM FORESE – Chairman
BOB BURNS
DOUG LITTLE
ANDY TOBIN
BOYD W. DUNN

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
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 THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322 DECISION NO. 75975 **OPINION AND ORDER**

DATES OF HEARING:	September 8-22, 2016
PLACE OF HEARING:	Tucson, Arizona
PUBLIC COMMENTS:	August 31, 2016
PLACE OF PUBLIC COMMENTS:	Tucson, Arizona
ADMINISTRATIVE LAW JUDGE:	Jane L. Rodda
IN ATTENDANCE AT PUBLIC COMMENT:	Doug Little, Commissioner Bob Stump, Commissioner Bob Burns, Commissioner Andy Tobin, Commissioner
APPEARANCES:	Mr. Michael W. Patten, SNELL & WILMER, LLP, and Mr. Bradley S. Carroll, Tucson Electric Power Company, for Tucson Electric Power Company; Mr. Thomas Loquvam, PINNACLE WEST CAPITAL CORPORATION LAW DEPARTMENT, on behalf of Arizona Public Service Company;

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Mr. Court S. Rich, ROSE LAW GROUP, PC, for Energy Freedom Coalition of America;

Mr. Daniel W. Pozefsky, Chief Counsel, and Jordy Fuentes, Staff Attorney for the Residential Utility Consumer Office;

Mr. Scott S. Wakefield, HIENTON & CURRY, PLLC, on behalf of Wal-Mart Stores, Inc. and Sam's West, Inc.;

Ms. Meghan H. Grabel and Ms. Kimberly Ruht, OSBORN MALEDON, PA, on behalf of Arizona Investment Council;

Mr. Timothy Hogan, ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST, on behalf of Southwest Energy Efficiency Project, Western Resource Advocates, Arizona Community Action Association, and local counsel for Vote Solar;

Mr. Michael Hiatt, Staff Attorney, Earthjustice, on behalf of Vote Solar;

Mr. Patrick Black and Mr. C. Webb Crockett, FENNEMORE CRAIG, PC on behalf of Freeport Minerals Corporation and Arizonans for Electric Choice and Competition;

Mr. Lawrence V. Robertson, Jr, of counsel for MUNGER CHADWICK, PLC, on behalf of Noble Americas Energy Solutions, LLC and Southern Arizona Home Builders Association;

Mr. Jeffrey W. Crockett, CROCKETT LAW GROUP, PLLC, on behalf of Tucson Meadows LLC;

Mr. Kyle J. Smith, General Attorney, U.S. ARMY LEGAL SERVICES AGENCY, Regulatory Law Office, on behalf of the Department of Defense and all other Federal Executive Agencies;

Ms. Camila Alarcon, GAMMAGE & BURNHAM, PLC, and Michelle Van Quathem, LAW OFFICES OF MICHELLE VAN QUATHEM, on behalf of Solon Corporation;

Mr. Nicholas J. Enoch, LUBIN & ENOCH, PC on behalf of International Brotherhood of Electrical Workers Local 1116;

Mr. Kurt Boehm, BOEHM, KURTZ & LOWRY, on behalf of The Kroger Co.;

Mr. Charles Wesselhoft, PIMA COUNTY

ATTORNEY'S OFFICE, on behalf of Pima County;

Mr. Keven Koch, *in propria persona*;

Mr. Bruce Plenk, *in propria persona*; and

Ms. Robin Mitchell, Mr. Brian E. Smith and Mr. Wesley C. Van Cleve, Staff Attorneys, Arizona Corporation Commission, Legal Division, for the Utilities Division.

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I. Background

A. Procedural History

Tucson Electric Power Company ("TEP" or "Company"), serves almost 415,000 customers in Pima County, of which approximately 90 percent are residential, 9 percent are commercial and less than 1 percent are industrial/mining.[1] TEP also provides power to Fort Huachuca, a U.S. Army base located in Cochise County. The Company's service territory includes 1,155 square miles. As of June 30, 2015, TEP owned or participated in an overhead electrical Transmission and Distribution system consisting of 616 circuit-miles of 500-kV lines, 1,109 circuit-miles of 345-kV lines, 350 circuit-miles of 138-kV lines, 479 circuit-miles of 46-kV lines, and 2,615 circuit-miles of lower voltage primary lines. TEP also operates 4,380 cable-miles of underground electric distribution lines and 106 electric substations with a total installed transformer capacity of 13,132,404 kilovolt amperes.[2] The Company owns 2,454 MW of generating capacity of which 50 percent is coal fired and 50 percent is gas fired, and owns 42 MW of solar generating capacity at ten different projects throughout the state.[3] Through 12 separate purchase power agreements ("PPA"), TEP has contracted for 221 MW of various solar, wind, and biogas resources in Arizona and New Mexico.[4]

TEP is a wholly-owned subsidiary of UNS Energy Corporation ("UNS Energy"). UNS Energy was purchased by Fortis, Inc. ("Fortis") in August 2014. Fortis is an investor-owned utility holding company based in St. John's Newfoundland and Labrador, Canada.[5] UNS Energy is also the parent of UNS Electric, Inc. ("UNSE"), which provides electric service in Santa Cruz and Mohave Counties.

On November 5, 2015, TEP filed with the Arizona Corporation Commission ("Commission") an Application for a Rate Increase, with accompanying Testimony and Exhibits ("Rate Case"). In its Rate Case Application, TEP requested an increase in rates that would result in a non-fuel revenue increase of approximately $109.5 million, or approximately 12 percent over adjusted test year

[1] Ex TEP-18 Gray Dir at 2.
[2] *Id.*
[3] Ex TEP-24 Sheehan Dir at 2.
[4] *Id.* at 3.
[5] Ex TEP-10 Bulkley Dir at 1.

revenues.[6] TEP also sought approval of: "(i) critical modifications to its rate design and net metering tariff; (ii) modifications to its Purchased Power and Fuel Adjustment Clause mechanism ("PPFAC"), its Environmental Compliance Adjustor ("ECA") and Lost Fixed Cost Recovery mechanism ("LFCR"); (iii) updated depreciation rates; (iv) modifications to its Tariffs and Rules and Regulations; and (v) other related matters."[7] One of the other matters is a buy-through rate tariff that the Company had agreed to propose as part of the settlement agreement approved in the Fortis acquisition of UNS Energy.[8]

On April 6, 2016, the Rate Case was consolidated with TEP's 2016 Renewable Energy Standard Tariff Implementation Plan ("2016 REST Plan") in order that rates associated with the Tucson Owned Rooftop Solar ("TORS") program and the Residential Community Solar ("RCS") program (proposed as part of the 2016 REST Plan) could be addressed in the Rate Case.[9]

By Procedural Order dated August 22, 2016, issues raised in the Rate Case related to "changes to net metering and rate design for new DG customers" were deferred to Phase 2, which would follow the conclusion of Docket No. E-00000J-14-0023, *In the Matter of the Commission's Investigation of Value and Cost of Distributed Generation* ("Value of DG" or "Value of Solar" docket).[10]

Intervention has been granted to: the Residential Utility Consumer Office ("RUCO"), Pima County, Freeport Minerals Corporation ("Freeport") and Arizonans for Electric Choice and Competition ("AECC"), International Brotherhood of Electrical Workers Local 1116 ("IBEW"), Noble Americas Energy Solutions, LLC ("NS"), Arizona Investment Council ("AIC"), Vote Solar, Sierra Club, The Alliance for Solar Choice ("TASC"), the Energy Freedom Coalition of America ("EFCA"), Arizona Public Service Company ("APS"), the Arizona Solar Energy Industries Association, the Arizona Utilities Ratepayers Alliance, Wal-Mart Stores, Inc. and Sam's West, Inc. (collectively "Wal-

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[6] TEP's requested retail revenues represent a 7 percent increase over the annualized revenue based on rates currently in effect which include a higher fuel cost component. Ex TEP-1 Application at 1. TEP utilized a test year ended June 30, 2015.

[7] *Id.*

[8] *See* Decision No. 74689 (August 12, 2014).

[9] The Commission issued Decision No. 75815 on November 22, 2016, which addressed issues related to expansion of the TORS program and the public benefit of the RCS program.

[10] The Commission had earlier deferred consideration of the same issues in the rate case of TEP's sister company, UNSE. *See* Decision No. 75697 (August 19, 2016). The Commission issued a Decision in the Value of Solar docket on January 3, 2017. *See* Decision No. 75859.

Mart"), the Kroger Co. ("Kroger"), Western Resource Advocates ("WRA"), the Southwest Energy Efficiency Project ("SWEEP"), Arizona Community Action Association ("ACAA"), SOLON Corporation ("SOLON"), Arizona Competitive Power Alliance, the Department of Defense and Federal Executive Agencies ("DOD"), the Southern Arizona Home Builders Association ("SAHBA"), Tucson Meadows, LLC ("TM"), Arizona Solar Deployment Alliance, and the following individuals: Kevin Koch, Bryan Lovitt and Bruce Plenk.

B. <u>Initial Positions</u>

TEP based its revenue requirement on a Fair Value Rate Base ("FVRB") of $2.91 billion, using a 50/50 weighting of an Original Cost Rate Base ("OCRB") of $2.10 billion and a Replacement Cost New Less Depreciation ("RCND") rate base of $3.72 billion.[11] TEP used its actual capital structure, adjusted for long-term debt retirements that occurred shortly after the test year, to determine the weighted average cost of capital ("WACC"). With the adjusted capital structure of 50 percent debt and 50 percent equity, a cost of long-term debt of 4.32 percent, and proposed cost of equity of 10.35 percent, the Company proposed a WACC of 7.34 percent.[12] With a proposed return on the fair value increment of 1.42 percent, TEP proposed a Fair Value Rate of Return ("FVROR") of 5.69.[13]

Although TEP's requested revenue increase of $109.5 million (an increase of 12 percent over adjusted test year revenues of $909.3 million) was not inconsequential, the key issues in this Rate Case involve revenue allocation and rate design. TEP claims that most of its costs related to owning and operating generating plants, transmission lines, distribution poles and wires, and transformers are fixed, but the vast majority of these costs are being recovered in "per kilowatt hour" ("kWh") charges. Thus, TEP asserts that as billed kWhs continue to decline due to conservation, energy efficiency ("EE") programs and distributed generation ("DG") requirements, the Company is left with unrecovered fixed costs. However, TEP notes that declining kWh sales do not mean that customers are relying less on the system, as the Company's peak demand has increased even as energy sales have decreased. Consequently, in its Application, TEP proposed several provisions to address the alleged mismatch between fixed costs and volumetric rates including: (1) updates to its LFCR by expanding the costs

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[11] Ex TEP-1 Application at 4. The FVRB was $645 million greater than in TEP's last rate case.
[12] *Id.* at 5.
[13] Ex TEP-10 Bulkley Dir at 64.

allowed to be recovered under the mechanism; (2) increasing the monthly basic service charge; (3) reducing the current four volumetric rate tiers for residential customers to two tiers; and (4) reducing the subsidies paid by commercial and industrial customers to residential customers.

In Direct Testimony, Staff made several adjustments affecting the proposed rate base, expenses, revenues and net operating income, resulting in a recommended revenue increase of no more than $49.4 million, or an average increase of approximately 5 percent over adjusted test year revenues.[14] Staff recommended a FVRB of $2,886,869,000.[15] Staff's revenue requirement was based on a FVROR of 5.00 percent, comprised of a cost of debt of 4.14 percent, cost of equity of 9.35 percent, and return on the fair value increment of 0.70 percent.[16] Staff modified the Company's revenue allocation to avoid any class receiving a rate decrease and recommended changes to the proposed rate designs.[17]

In its Direct Testimony, RUCO recommended total operating revenue of $959.3 million, an increase of $17.387 million, or 1.85 percent, over RUCO's adjusted test year revenues of $941.9 million.[18] RUCO recommended a FVRB of $2.582 billion. RUCO recommended utilizing a capital structure comprised of 49.97 percent debt, with a cost of 4.32 percent, and 50.03 percent equity with a cost of equity of 9.2 percent.[19] RUCO recommended a fair value increment adjustment of 1.56 percent, resulting in a FVROR of 5.20 percent.[20]

The DOD did not analyze the Company's proposed rate base or operating revenues and expenses, but focused on the Company's proposed Class Cost of Service Study ("CCOSS"), revenue allocation among the various rate classes, and on the cost of capital. In general, the DOD supports moving rate classes to their cost of service as indicated by the CCOSS. In this case, given the current wide disparity of class returns, DOD recognized that moving the classes to cost of service was not possible without significant disruptions and rate shock. Thus, DOD generally supported TEP's proposed revenue allocations in Direct Testimony, but noted that if the ultimate revenue requirement

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[14] Ex S-1 Mullinax Dir at 6.
[15] *Id.* at 7.
[16] Ex S-3 Parcell Dir at 49. In Direct Testimony, Staff utilized a capital structure of 51.31 percent long term debt and 48.69 percent equity.
[17] *See generally* S-10 Solganick Dir.
[18] Ex RUCO-4 Michlik Dir at 4.
[19] Ex RUCO-2 Mease Dir at ii.
[20] *Id.*

is less than TEP's initial request, that no reduction be made to the proposed allocation to the Residential class and that the reduction be applied to the General Service ("GS"), Large General Service ("LGS") and Large Power Service ("LPS") classes.[21] In Direct Testimony, DOD recommended an OCRB rate of return of 6.74 percent, based on a cost of equity of 9.3 percent, cost of debt of 4.32 percent, and the actual test year capital structure of 48.69 percent equity and 51.31 percent debt.[22] DOD recommended a FVROR of 5.0 percent, which resulted in a recommended increase in revenue of $76.0 million.[23]

SWEEP recommended that TEP's approved EE program budget of $23 million be recovered in base rates rather than through the Demand Side Management ("DSM") adjustor.[24] All else being equal, SWEEP's recommendation would increase operating expenses, and thus affect the revenue increase, although with the DSM surcharge reduced by a commensurate amount, the impact on the rate payers' bills would not change.

Although other parties had recommendations concerning the CCOSS, revenue allocation, proposed tariffs and rate design, as well as various other issues, they did not provide Direct Testimony concerning specifics of the revenue requirement.[25]

Following notice of settlement discussions, some of the parties to this proceeding entered into a settlement agreement dated August 15, 2016 ("Settlement Agreement" or "Agreement") that purports to resolve the revenue requirement portion of the proceeding. The Settlement Agreement was entered into by: TEP, RUCO, Freeport and AECC, Kroger, Wal-Mart, AIC, Sierra Club, WRA, and Staff. The Settlement Agreement was not entered into by all parties to the proceeding, and it did not address all issues, leaving open the allocation of revenue among the rate classes, rate design, the LFCR, PPFAC, net metering, and the Buy-Through Tariff, as well as other issues discussed herein.

II. The Settlement Agreement

A. Terms of the Agreement

A copy of the Settlement Agreement is attached hereto as Exhibit A. The Agreement provides for a non-fuel revenue requirement of $714,022,900 which is a base rate revenue increase of $81.5

[21] Ex DOD-1 Brudaker Dir at 24-25.
[22] Ex DOD-3 Gorman Dir at 3.
[23] *Id.* at MPG-1.
[24] Ex SWEEP-1 Schlegel Dir at 8-9.
[25] Wal-Mart provided Direct Testimony related to the importance of the Cost of Capital. Ex Wal-Mart-1 Tillman Dir.

million over adjusted test year non-fuel retail revenues.[26] The average base fuel rate is to be set at $0.032559 to recover a total of $289,147,243 in base fuel revenues. The result is a total revenue requirement of $1,003,170,143.[27]

The parties supporting the Settlement Agreement have agreed that TEP's jurisdictional FVRB used to establish rates should be $2,843,985,854, based on the average of an OCRB of $2,045,203,460 and RCND of $3,633,027,972.[28]

When it filed its Rate Application, TEP was in the process of acquiring a 50.5 percent interest in the Springerville Generating Station Unit 1 ("SGS 1").[29] TEP originally proposed to recover the costs of operating SGS 1 through its PPFAC. The Settlement Agreement provides that the annual operating costs of approximately $15,243,913 will be recovered through non-fuel rates, but that this portion of the rate increase should not be effective until after the purchase is completed and a final Order issued.[30] The $15.2 million of operating costs associated with SGS 1 is included in the $81.5 million increase reflected in the Settlement Agreement. By providing for the recovery of the costs of SGS 1 in base rates instead of the PPFAC, the effect on the overall revenue increase is neutral. TEP agreed not to request rate base treatment for the 50.5 percent share in SGS 1 until its next general rate case.[31]

The Settlement Agreement provides for a capital structure of 49.97 percent long-term debt and 50.03 percent common equity. The proponents have agreed to a return on common equity ("ROE") of 9.75 percent and an embedded cost of long-term debt of 4.32 percent, resulting in a WACC of 7.04

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[26] Settlement Agreement at ¶ 2.1.
[27] *Id.* at ¶ 2.3.
[28] *Id.* at ¶ 2.5. Note that the FVRB in the Settlement Agreement overstates the average of the OCRB and RCND.
[29] In December 2014 and January 2015, TEP purchased leased interests in SGS 1 totaling 35.4 percent for an aggregate purchase price of $65 million, which brought TEP's ownership interest in the unit to 49.5 percent. Prior to January 1, 2015, TEP leased 100 percent of SGS 1 and owned an equity interest in one of the leases covering a 14 percent share of the unit. In its Application, TEP removed the lease costs from its revenue requirement and included adjustments to rate base and operating expenses to reflect the Company's 49.5 percent ownership interest. TEP sought approvals related to changes at the SGS, including an extended recovery period for leasehold improvements made to SGS common facilities as well as recovery of operating costs through the PPFAC for energy dispatched from the 50.5 percent co-owner share of SGS 1, to the extent that capacity is available to meet retail customer needs. Ex TEP-1 Application at 8.
[30] Settlement Agreement at ¶2.4. During the Hearing, Mr. Sheehan testified that the purchase of the SGS 1 had received FERC approval and the transaction was expected to close on September 16, 2016. Transcript of the Hearing ("Tr.") at 1242. TEP filed notice on September 26, 2016, that it had completed the purchase.
[31] Settlement Agreement at ¶5.2. The leasehold improvements associated with the 50.5 percent interest in SGS 1 will be updated in the OCRB at the Net Book Value as of December 31, 2016, and amortization of these assets will continue as approved in TEP's last rate case. *See* Decision No. 73912 (June 27, 2013).

percent. The Settlement provides for a FVROR of 5.34 percent, which includes a rate of return on the fair value increment of 1.0 percent.[32]

The Settlement Agreement accepts the depreciation and amortization rates as proposed by TEP in its Rebuttal Testimony <u>except</u>: (1) the rates for the San Juan Generating Station ("San Juan") will be adjusted to reflect a depreciable life of TEP's total investment, including the Balanced Draft project, at San Juan Unit 1, or six remaining years; (2) $90 million of excess depreciation reserves will be transferred to San Juan Unit 1; and (3) depreciation rates on TEP's distribution plant are reduced to offset the increase in depreciation expense for San Juan Unit 1.[33]

The Settlement Agreement provides that TEP will write down the Net Book Value of its headquarters building by $5 million, resulting in a $5 million reduction to OCRB, within 30 days of the issuance of a final order in this proceeding. In return, the signatories to the Settlement Agreement agree that they will not seek alternate rate treatment or additional write-down of the headquarters building in future rate proceedings.[34]

The Settlement Agreement provides that post-test year plant in the amount of $49.6 million and post-test year renewable generation plant of $4.8 million that is verified and in-service as of June 30, 2016, will be included in the Company's OCRB.

B. Arguments in Favor of Settlement Agreement

1. TEP

TEP states that the Settlement Agreement is supported by diverse interests and is the product of an open, transparent process that balances the interests of a variety of stakeholders.[35] TEP argues that the Agreement's terms are fair and reasonable. The Company notes that the non-fuel revenue increase agreed to in the Settlement Agreement is $44.3 million less, or approximately 65 percent, of its original request in the Application (when the operating costs of SGS 1 that would have been

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[32] Settlement Agreement at ¶¶ 3.1 – 3.3.

[33] *Id.* at ¶ 4.1. By accelerating depreciation on San Juan Unit 1, the parties believe that it will be easier for TEP to make a decision about the continued operation of this unit in 2022 when the Fuel Supply Agreement and Plant Participation Agreement expire.

[34] *Id.* at ¶ 6.1

[35] TEP Opening Brief at 3.

recovered it the PPFAC are factored in).[36] In addition, TEP states that the Settlement Agreement reduces the Company's requested OCRB by $59.5 million.[37]

TEP claims that the Settlement Agreement provides momentum to its generation diversification strategy by recovering non-fuel operating costs related to its 50.5 percent acquisition of SGS 1 and reducing the book value and depreciation lives related to its existing coal generation assets.[38] By modifying the depreciation reserves and rates for San Juan Unit 1, TEP's investment in the unit will be almost fully depreciated by 2022 when the current coal supply contract and participation agreement expire. TEP states that this, along with the additional SGS 1 capacity, gives TEP more flexibility in its resource portfolio after 2022, and allows TEP to exit San Juan without large cost impacts on customers.[39] TEP states that the acquisition of the remainder of SGS 1 means ratepayers benefit from a reliable, low-cost base load resource that utilizes TEPs existing bulk transmission assets and supports a significant portion of the Company's ancillary service requirements.

TEP also argues that the Settlement Agreement's revenue requirement will help the Company maintain or improve its investment-grade credit ratings.[40] Other credit-supportive aspects of the Agreement, according to TEP, include an authorized ROE that is comparable to the recent ROEs approved for other vertically integrated investor-owned utilities; a capital structure that reflects the significant improvement in equity since the last rate case and the acquisition of UNS Energy by Fortis; and recovery of non-fuel operating and maintenance costs related to the recent purchase of the remaining 50.5 percent of SGS 1.[41]

The Settlement Agreement adopts TEP's capital structure at the end of the test year consisting

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[36] *Id.* at 4.

$ in millions	Initial Position	Settlement	Change
Non-fuel Base Rate Increase	$109.50	$66.30	-$43.2
Treatment of Non-Fuel O&M related to 50.5 % of SGS 1:			
PPFAC Recovery	$16.30	$0.00	-$16.30
Non-fuel Base Rates	$0.00	$15.20	$15.20
Total	$125.80	$81.50	-$44.30

[37] No party objected to the Settlement's proposed OCRB, except that EFCA has argued that $16,000 associated with TORS should not be included.

[38] TEP Opening Brief at 6; Ex TEP-6 Hutchens Settlement at 5.

[39] TEP Opening Brief at 6.

[40] *Id.* TEP is currently rated A3 by Moody's Investor Services and BBB+ by Standard & Poor's. Ex TEP-6 Hutchens Settlement at 4.

[41] Ex TEP-6 Hutchens Settlement at 4.

of 49.97 percent long-term debt and 50.03 percent common equity; an ROE of 9.75 percent (compared to the Company's original requested ROE of 10.35 percent); and a fair value increment rate of return of 1.0 percent, compared to TEP's originally requested 1.42 percent. TEP states that the impact of these elements reduces the Company's requested non-fuel revenue increase by approximately $15.5 million.[42]

TEP argues that the Settlement's 9.75 percent ROE is within the approved ROEs of the proxy groups used by the only party who challenged the Settlement's finding.[43] TEP argues that the Settlement ROE of 9.75 percent is appropriate as compared to the 9.5 percent ROE authorized for UNSE because TEP has a much larger generation fleet that includes a significant amount of coal-fired generation and the inherent risk associated with increased economic regulation.[44] TEP explains that the capital structure adopted in the Settlement Agreement recognizes that TEP redeemed certain bonds several weeks after the end of the test year.[45] TEP argues that in recognizing that TEP was legally obligated to redeem the bonds, the Settlement Agreement accounts for known and measurable changes to the test year capital structure, and that the capital structure is not based on a transaction that "may" or "may not" occur.[46]

TEP also argues that the 1.0 percent return on the fair value increment of rate base is supported by the record and consistent with prior Commission approaches to the fair value increment. In Ms. Bulkely's Rebuttal Testimony, she calculated the return on the fair value increment to be 1.07 percent, and Staff's witness Mr. Parcell calculated the fair value increment (real risk-free rate) to be as high as 1.42 percent. Based on the record, TEP argues that the 1.0 percent compromise is reasonable.[47]

Further, TEP states that the Settlement Agreement reduces TEP's pro forma operating expenses by $22.6 million over the Company's initial request. The more significant adjustments normalize generation overhaul and outage expenses based on the most recent six years of actual data; exclude the wage and payroll tax increase associated with anticipated 2017 non-union wage increases; recover only

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[42] TEP Opening Brief at 7.
[43] *Id. citing* Ex DOD-4 Forman Surr, Ex MPG-24. TEP states the ROEs of Mr. Gorman's proxy group ranged from 10.3 percent to 9.3 percent, with an average of 9.73 percent.
[44] Ex TEP-12 Bulkley RJ at 5; Tr. at 368.
[45] Ex TEP-12 Bulkley RJ at 9.
[46] TEP Opening Brief at 8.
[47] *Id.* at 8.

50 percent of the normalized cost associated with the Company's Short Term Incentive compensation plan; caps rate case expense at $1 million to be amortized over four years; remove expenses associated with the Company's Long Term Incentive compensation plan; reduce test year legal costs by $1.1 million; and conform changes to depreciation and income tax expenses associated with agreed upon depreciation rates and rate base changes.[48]

TEP asserts that the depreciation modifications are consistent with TEP's last rate case order in which the Commission acknowledged the reasonableness of applying excess depreciation reserves to offset the effects of early production plant retirements.[49] TEP states that using excess distribution depreciation reserves will mitigate the rate impact of the San Juan Unit 1 accelerated depreciation resulting from shortening the life to six years. TEP contends that given the uncertainty surrounding TEP's continued operation of San Juan Unit 1 after the expiration of the current Fuel Supply Agreement and Plant Participation Agreement in 2022, it is reasonable to shorten its expected useful life.[50]

2. <u>AIC</u>

AIC, a signatory to the Settlement, asserts that the Agreement is both in the public interest and beneficial to the financial health of the Company.[51] AIC asserts that although the agreed revenue requirement is 26 percent lower than the Company's original request, it is a reasonable compromise considering the starting positions of the parties to this case. AIC states that investors and credit rating agencies look favorably on settlement agreements because they resolve issues that would otherwise result in protracted litigation and regulatory delay. AIC contends that adopting the Settlement would be further indication of an improved regulatory climate conducive for investment in Arizona's utilities.

3. <u>RUCO</u>

RUCO argues that the Settlement Agreement is in the public interest for each of the following benefits:

(1) The revenue increase of $81.5 million includes $15.2 million related to the non-fuel operating costs associated with the acquisition of the 50.5 percent share of the SGS 1

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[48] *Id.* at 10; Ex TEP-23 Dukes Settlement at 3-4.
[49] Ex TEP-23 Dukes Settlement at 6.
[50] *Id.*
[51] AIC Opening Brief at 2.

(which originally the Company proposed be included in the PPFAC); thus, according to RUCO, the actual revenue increase is $66.3 million.[52]

(2) A permanent $5 million reduction to OCRB from the write down of the Net Book Value of the headquarters building.

(3) An $18.1 million reduction in post-test year plant being included in rate base.

(4) The adjustment of the depreciation rates for San Juan to reflect a depreciable life of six years, and the transfer of $90 million of excess distribution reserves to offset the change and to protect rate payers.[53]

(5) Lower authorized operating expenses including: the application of a six-year historical average of outage expenses; exclusion of increased 2017 payroll expenses for non-classified employees; a 50/50 sharing of short-term incentive compensation; rate case expense of $1 million normalized over four years; and removal of $1.1 million associated with litigation.

(6) The adoption of a cost of equity of 9.75 percent as compared to the 10.35 percent originally sought by the Company.

RUCO argues that the Settlement Agreement is a fair and reasonable resolution which benefits the Company's ratepayers while also providing the Company with a reasonable opportunity to earn its fair rate of return.[54]

4. AECC/Freeport/NS

AECC/Freeport/NS support the Settlement Agreement as a fair compromise of several contested issues, and a clear benefit to ratepayers due to the reduced revenue increase.[55]

5. Wal-Mart

Wal-Mart signed the Settlement Agreement, and notes that it is the result of arms-length negotiations between the parties, and adequately addresses the revenue requirement issues Wal-Mart raised in its testimony.[56]

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[52] RUCO Opening Brief at 3; Ex RUCO-5 Michlick Surr Attachment A at 4.
[53] Ex RUCO-5, Attachment A at 3.
[54] RUCO Opening Brief at 4.
[55] AECC/Freeport/NS Opening Brief at 2.
[56] Wal-Mart Opening Brief at 2; Ex Wal-Mart-3 Tillman.

6. Kroger

Kroger signed and fully supports the Settlement Agreement, which it states is the product of several rounds of negotiations between the Company and signatories, and reasonably balances the interests of the Company and its ratepayers.[57]

7. Sierra Club

Sierra Club's interest in this proceeding focused on the planned depreciation schedule for TEP's share of the San Juan Unit 1. Sierra Club signed the Agreement because the accelerated depreciation schedule for San Juan Unit 1 synchs with the end of the coal supply contract for the plant, and is the latest likely date that the unit will cease operation. Sierra Club asserts that accelerating the depreciation of San Juan Unit 1 is in the public interest because the entire San Juan plant is facing increasingly difficult economic conditions, and accelerating depreciation to coincide with its expected retirement date will ensure that only customers who receive power from San Juan will pay for the plant. Sierra Club states that the Settlement Agreement satisfactorily resolved all issues raised by Sierra Club testimony, and Sierra Club recommends that the Commission approve the Agreement as in the public interest.[58]

8. SAHBA

SAHBA did not file testimony in this proceeding and was not a signatory to the Settlement Agreement, however, SAHBA supports the settlement result of an $81.5 million non-fuel revenue requirement. SAHBA believes that it is important that TEP be in a position to continue to provide safe, adequate and reliable electric service, and presumes based on the Company's agreement to the Settlement, that it provides TEP with the support it needs to continue to provide such level of service.[59]

9. WRA

WRA signed and supports the Settlement Agreement for its treatment of the San Juan Unit 1.[60]

10. Staff

Staff asserts that the Settlement Agreement was the collaborative effort of parties with divergent

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[57] Kroger Opening Brief at 2.
[58] Sierra Club Opening Brief at 2.
[59] SAHBA Opening Brief at 2.
[60] SWEEP/WRA/ACAA Opening Brief at 21.

interests, working to narrow the contested issues in this proceeding.[61] Staff states that the one-day settlement conference was open, transparent and conducted at arm's length, with each participant given an opportunity to advance its position. Staff states that each of the signatories compromised on vastly different positions. Staff argues the Settlement Agreement furthers the public interest because it addresses TEP's revenue needs, promotes the convenience, comfort and safety, and preservation of health of the employees and patrons of TEP, resolves issues, and avoids litigation expense and delay.[62]

C. Arguments Against the Settlement Agreement

1. Capital Structure and Cost of Capital in Settlement is Unreasonable

a. DOD

DOD did not join the Settlement because it believes the revenue requirement is excessive and will produce rates that are not just and reasonable.[63] Specifically, DOD asserts that the Settlement is based on an inflated ROE and FVROR, and that the revenue requirement should be reduced by at least \$14.1 million.[64] DOD argues that the Settlement's agreed 9.75 percent ROE compares unfavorably to the industry average of authorized returns of 9.5 percent, and the record does not support a FVROR of 5.34 percent in combination with an ROE of 9.75 percent.[65] As shown below, DOD asserts that no non-Company witness recommended an ROE greater than 9.5 percent.[66]

Party	ROE Range/(Rec.)	FVROR
TEP (Bulkley)	10.00 %[67]	5.69%
Staff (Parcell)	9.2%-9.5 % (9.35%)	5.00%
DOD (Gorman)	8.9%-9.7% (9.3%)	5.00%
RUCO (Mease)	7.91%-9.65% (9.2%)	5.20%
Wal-Mart (Tillman)	Max 9.50%	N/A

Based on the results of his Discounted Cash Flow ("DCF"), Capital Asset Pricing Model

[61] Staff Opening Brief at 6-7.
[62] Ex S-20 Abinah Settlement Test. at 8.
[63] DOD Opening Brief at 2.
[64] DOD Reply Brief at 1. According to the DOD, \$11.1 million is attributed to overstating the rate of return, and \$3.0 million is due to using a pro forma capital structure. *Id.* at 3.
[65] DOD Reply Brief at 1.
[66] DOD Opening Brief at 3.
[67] 10.35 percent pre-Settlement.

("CAPM"), and risk premium analyses, Mr. Gorman recommended a range for TEP's ROE of 8.90 percent to 9.70 percent, with a midpoint of 9.30 percent. DOD asserts that an ROE of 9.3 percent would fairly compensate investors for TEP's total investment risk, as it would preserve TEP's financial integrity and support an investment grade bond rating.[68] DOD takes issue with TEP's claim that it did not consider TEP's specific risk (including its capital structure, its generation mix fuel diversity, relative size vis-a-vis the proxy group and rapid deployment of DG in its service area) and claims that Mr. Gorman considered TEP's specific risk by reviewing credit and equity analysts' assessments of TEP, the proxy group, and industry risk.[69]

Mr. Gorman criticized Ms. Buckley's analysis on the grounds that: (1) her constant growth DCF model is based on excessive and unsustainable growth estimates; (2) her multi-stage DCF is based on an unrealistic gross domestic product ("GDP") estimate; (3) her CAPM assumes inflated market risk premiums; (4) her bond yield plus risk premium model is based on inflated equity risk premiums; and (5) her risk premium studies are based on stale Treasury yields. DOD asserts that its analysis shows that current market conditions are favorable for the utility industry in general, and TEP specifically, as DOD claims the Company has lower risk and market cost, and less volatility than the overall market.

Mr. Gorman used three types of DCF models: a Constant Growth DCF, a Sustainable Growth DCF and a Multi-stage DCF.[70] For his Constant Growth DCF, Mr. Gorman used an average stock price rather than the spot price to mitigate the effect of market variations. For dividend growth he adjusted *Value Line's* reported quarterly dividends, for next year's growth, and used the average growth rates of the proxy group for the earnings growth estimate. His Sustainable Growth DCF model is based on the percentage of earnings retained by the utility. In his Multi-Stage Growth DCF Model, which captures expectations that a utility would have changing growth rates over time, Mr. Gorman used three growth periods, a short-term period of five years; a transition period for years 6 through 10; and a long-term growth period starting in year 11through perpetuity. DOD asserts that Mr. Gorman's multi-stage DCF relies on consensus analysts' estimates that provide relevant information to investors, and

[68] DOD Opening Brief at 19.
[69] DOD Reply Brief at 2.
[70] DOD states that DCF models are based on the assumption that a current stock price represents the present value of all future cash flows and dividend growth rate is central to the analysis. All things being equal, the higher the growth rate, the higher the ROE.

criticism that it produces lower results relative to historical estimates is without merit.[71] Based on the totality of his DCF results, Mr. Gorman recommended an ROE of 8.7 percent, primarily based on his Constant Growth model.[72]

Mr. Gorman's Risk Premium model used two estimates of an equity risk premium – the difference between the required return on utility common equity investments and U.S. Treasury bonds for the period 1986 through 2016, and the difference between regulatory commission-authorized returns on common equity and contemporary Moody's "A" rated utility bond yields for the same period.[73] DOD argues that criticisms of the Risk Premium model should be rejected because they ignore investment risk differentials in favor of a simplistic inverse relationship between equity risk premiums and interest rates.[74]

The inputs for Mr. Gorman's CAPM are an estimate of the market risk-free rate, the Company's beta, and the market risk premium.[75] Mr. Gorman used the 30-year Treasury bond yield for the risk-free rates, and for the beta, he used the average *Value Line* estimate for the proxy group. Mr. Gorman developed two estimates of the market risk premium -- a forward-looking estimate based on the expected return of the S&P 500 less the risk-free rates, and an historical estimate based on the average S&P 500 returns from 1926 to 2014 less the total return on long-term Treasury bonds. Mr. Gorman's recommended CAPM return estimate was 9.1 percent.[76]DOD argues that criticism of Mr. Gorman's historical market risk premium does not reflect the current market condition is "without merit" because he captures current market conditions by giving 75 percent weight to his high-end estimates. Mr. Gorman asserts that the Company's forward-looking market return is based on overstated growth rate

[71] DOD Opening Brief at 12.
[72] Ex DOD-4 Gorman Surr at 36. Mr. Gorman's DCF results are summarized as follows:

Description	Average	Median
Constant Growth DCF- analysts Growth	8.71%	8.70%
Constant Growth DCF-Sustainable Growth	8.06%	7.72%
Multi-Stage Growth DCF	7.99%	7.89%
Average	8.25%	8.10%

[73] The Risk Premium model is based on the concept that investors require a higher return to assume greater risk.
[74] DOD Opening Brief at 15.
[75] CAPM is based on the concept that the market-required rate of return for a security equals the risk-free rate plus a risk premium associated with the specific security.
[76] Ex DOD-3 Gorman Dir at 49.

estimates.[77]

DOD argues that the Company's recommended ROE of 10.0 percent is unreasonable and should be rejected as it substantially exceeds a fair rate of return. DOD argues that Ms. Bulkley's constant growth DCF (which produced ROE estimates of 9.29 percent to 9.59 percent, with a mid-point of 9.45 percent) assumes a growth rate for her proxy group of 5.55 percent which Mr. Gorman states is substantially higher than analysts' growth outlooks.[78] DOD argues that Ms. Bulkley's multi-stage DCF results are illogical and suspect because they use a lower growth rate of 5.4 percent relative to the average growth rate in her constant growth DCF model, but produce higher multi-stage DCF returns. DOD claims Ms. Bulkley used an inflated long-term growth rate that uses the GDP growth rates for the period 1929 to 2014 and adds a current inflation rate to create a nominal GDP growth rate. DOD asserts that Ms. Bulkley fails to explain the basis of her assumption that a historical real GDP growth rate is appropriate for projecting future growth. DOD argues that the world economy has changed significantly since 1926, and Ms. Bulkley provided no credible evidence that the U.S. economy will grow at the exact rate in the future as in the past, nor evidence that investors expect the historical rate to prevail in the future.[79] In addition, DOD asserts that Ms. Bulkley overstates the COE of the proxy group by using an historical real GDP rate that is significantly higher than the projection of "consensus economists."[80] DOD states that Ms. Bulkley's CAPM analysis uses inflated market risk premiums based on a far too high market index growth rate and used risk-free rates that are almost a year old.[81]

DOD argues that because Ms. Bulkley assumed a simple inverse relationship between the level of interest rates and the equity risk premium, the regression analysis she utilized to increase the risk premium in her bond yield analysis was improper and unreasonable.[82]

DOD disputes TEP's proposed capital structure of 50.03 percent common equity and 49.97 percent debt because it was not the actual capital structure at the end of the test year, but was adjusted

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[77] DOD Opening Brief at 18

[78] *Id.* at 20.

[79] *Id.* at 21.

[80] *Id.* DOD states economists project 2.1 percent and claims that had Ms. Bulkley used the economists' projections for the GDP growth rate, her Multi-stage DCF estimated return would be reduced from 9.62 percent to 8.68 percent.

[81] DOD Opening Brief at 22. DOD recalculates Ms. Bulkley's CAPM analysis to use (1) her updated current (2.72 %), near-term (3.15 %), and projected (4.5%) risk-free rates; (2) beta estimates of 0.696 (*Value Line*) and 0.767 (Bloomberg); and (3) a market premium of 7.0 % the highest Morningstar estimate), results in a CAPM estimated return no higher than 8.8 %.

[82] DOD Opening Brief at 23.

to reflect the post-test year retirement of two debt issuances. DOD recommends using the actual capital structure consisting of 48.69 percent common equity and 51.31 percent long-term debt. DOD asserts that "TEP's actual capital structure has supported the Company's strong investment grade credit rating while allowing TEP to access external capital at reasonable prices to support its capital improvement programs."[83] Thus, DOD argues that there is no justifiable reason to increase the Company's common equity ratio and inflate the revenue requirements.

DOD criticizes the Company's estimate of the FVROR for relying on projections of Treasury bond yields five to ten years into the future, rather than currently observable cost of capital.[84] DOD modified Ms. Bulkley's method to use current Treasury bond yields and Treasury bond yield projected by independent economists to conclude that the FVROR should be no higher than 5.1 percent.[85] DOD believes that adding an incremental rate of return to the OCRB rate of return is inappropriate as Mr. Gorman explains:

> The primary difference between an ROR-OCRB and an ROR-FVRB relates to compensating investors for the expected investment growth. In an ROR-OCRB, the expected growth rate in asset values is included in the rate of return and investors are compensated for this growth in the utility's operating income. Conversely, in a fair value methodology, expected growth in the value of the assets is picked up in the growth to the rate base itself, and not in the rate of return.[86]

Even though Mr. Gorman disagrees with the Company's application of the fair value methodology, he revised the Company's proposed 0.54 percent rate of return increment to reflect his proposed actual capital structure, recommended ROE of 9.3 percent, and his updated risk-free rate of 0.92 percent, to derive a fair value increment of only 0.18 percent.[87]

b. Staff Response to DOD

Staff continues to support the Settlement Agreement because the ROE, FVROR and capital structure are appropriate and reasonable compromises, and notes that even Mr. Gorman's proxy group companies had recently approved ROEs ranging from 9.3 percent of 10.3 percent.[88]

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[83] *Id.* at 24.
[84] DOD Reply Brief at 2.
[85] DOD Opening Brief at 26.
[86] Ex DOD-3 Gorman Dir at 71.
[87] DOD Opening Brief at 27.
[88] Staff Reply Brief at 2; Ex DOD-4 Gorman Surr at MPG-24.

Staff asserts that the capital structure adopted in the Settlement Agreement, which accounted for the redemption of bonds that occurred several weeks after the test year, was an adjustment that was known and measurable.[89] Staff believes that adopting the pro forma capital structure was reasonable as TEP was legally obligated to redeem the debt during the test year and the redemption process was nearly completed by the end of the test year.

Staff's witness, Mr. Parcell, calculated the risk free rate to be 1.4 percent and recommended a fair value increment at the midpoint between zero and 1.4 percent, or 0.70 percent.[90] Staff notes that in Rebuttal Testimony, TEP calculated the fair value increment to be 1.07 percent.[91] Thus, Staff argues the Settlement's proposed 1.0 percent fair value increment is a reasonable compromise and should be adopted.

c. **TEP Response to DOD**

TEP states that the DOD is the only party contesting the Settlement's ROE, even though its own witness' analysis shows a range of returns up to 9.70 percent.[92] TEP states that DOD's position seems to suggest that TEP should be below the average of recently authorized ROEs (which ranged from 9.58 percent to 9.8 percent), despite a lack of evidence showing TEP has lower risk than other vertically integrated electric utilities. TEP states that looking more closely at the 2015 and 2016 average authorized returns shows absolute ranges from 9.30 percent to 10.30 percent.

TEP argues that DOD's recommendation that the ROE for TEP should be no more than 9.5 percent is inconsistent with the evidence provided by Mr. Gorman that included:

(1) A recommended range for ROEs from 8.9 percent to 9.7 percent which exceeds the threshold established by DOD.

(2) A range of authorized ROEs for integrated electric utilities from 9.3 percent to 10.3 percent, with an average of 9.7 percent.

(3) A range of authorized returns in litigated cases from 9.66 percent to 9.72 percent, with a midpoint of 9.69 percent; and

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[89] Staff Reply Brief at 2; Ex TEP-11 Bulkley Reb at 51

[90] Staff Reply Brief at 2; Ex S-3 Parcell Dir at 48.

[91] Tr. 262.

[92] DOD Opening Brief at 3.

(4) The average authorized ROEs for vertically integrated electric utilities in settled and litigated cases in the range of 9.63 percent to 9.78 percent for the period 2015-2016.[93]

TEP claims Mr. Gorman's DCF and CAPM results are significantly below recently authorized ROEs.[94] TEP states that over the period 2013 through 2016, there has not been a single authorized ROE that is within the range of Mr. Gorman's DCF analysis, and that his CAPM recommendation of 9.1 percent is 53 basis points below the low end of the range of recently authorized ROEs for vertically integrated electric utilities.[95] TEP states that the only methodology developed by Mr. Gorman that is within the range of recently authorized ROEs is his Risk Premium approach which estimates a ROE between 9.60 percent and 9.80 percent. TEP notes that the Settlement Agreement ROE of 9.75 percent falls within this range.[96] TEP argues that the DOD did not consider the size and nature of TEP's generation fleet, the increased risk of rapid DG deployment in TEP's service area, nor the rate design or revenue decoupling mechanism specific to TEP.[97]

Furthermore, TEP asserts that the reasonableness of Ms. Bulkley's analyses is demonstrated by the fact that her results (an initial ROE of 10.3 percent and final ROE of 10.0 percent) are within the range established by recently authorized ROEs for vertically integrated utilities. TEP asserts that the DOD's focus on Ms. Bulkley's recommended FVROR of 1.07 percent rather than the lower 1.0 percent contained in the Settlement, is not relevant to the Commission's decision on the Settlement Agreement.

2. Energy Efficiency and DSM Program Costs Included in Base Rates

a. SWEEP

SWEEP did not oppose the Settlement Agreement per se, but argues that the cost of TEP's approved EE programs should be included in base rates. As such, SWEEP's proposal would add $23 million to base rates to fund the Company's approved EE programs. The total ratepayer bill would not be affected as the DSM surcharge would be reduced a commensurate amount.

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[93] Ex DOD-4 Gorman Surr at 4, 7 and MPG-24.
[94] TEP Reply Brief at 4. Mr. Gorman's DCF results ranged from 7.22 to 8.71 percent, with a recommendation of 8.7 percent, and his CAPM resulted in a range from 8.01 percent to 9.44 percent with a recommendation of 9.2 percent.
[95] Ex DOD-4 Gorman Surr. Ex MPG-24.
[96] TEP Reply Brief at 5.
[97] Tr. at 831-33.

Mr. Schlegel explained that TEP's 2014 Integrated Resource Plan ("IRP") projects that energy efficiency will contribute approximately 22 percent of the utility's future additional capacity resources from 2015-2018, and also identifies energy efficiency as its "lowest cost resource." [98] Further, SWEEP notes that the IRP and annual DSM reports show that energy efficiency costs substantially less than other resource options.

SWEEP claims that currently TEP does not treat cost recovery of major energy resources in a consistent and equitable manner because it uses adjustor funding for EE, and shows the adjustor cost recovery separately on the customer's bill, but recovers the costs of other resources in base rates. SWEEP asserts TEP is not being transparent regarding the costs of the other energy resources. Because it is a core resource that meets actual energy needs, SWEEP argues that energy efficiency should be adequately funded through a stable, fully embedded funding and cost recovery mechanism consistent with the treatment of other energy resources. SWEEP recommends that energy efficiency program costs be recovered in base rates, and that the Commission order TEP to recover $23 million annually, consistent with the total Commission-approved budget for TEP's 2016 energy efficiency portfolio.

Under SWEEP's proposal, the Commission's review and approval of EE programs and budgets would continue to be done through the DSM Implementation Plan process. The DSM adjustor mechanism would remain intact, but would be used as an adjustor to recover or refund any energy efficiency funding amounts above or below the $23 million in base rates needed to implement Commission-approved programs.

SWEEP believes that TEP should treat all energy resources equitably in terms of disclosure and transparency on bills and in customer communications. Thus, SWEEP recommends that TEP provide information to customers on the ratepayer costs of major energy resources at all times via the web, and quarterly or annually via a bill insert, email, and/or other communication (and not on the bill itself). SWEEP states that the information on the costs of energy resources could include a simple and transparent pie chart that illustrates how each dollar of the utility bill is spent, with the ratepayer costs associated with each and every energy resource (and other costs) clearly delineated. SWEEP states

[98] Ex SWEEP-1 Schlegel Dir at 8.

that currently TEP does not provide any such transparency regarding the ratepayer costs of other major energy resources either on the bill, or in any other manner. SWEEP recommends that the Commission order TEP, within 120 days of the Order in this proceeding, to file a proposal to provide information to customers on the ratepayer costs of major energy resources at all times via the web, and quarterly or annually via a bill insert, email, and/or other communications, and that TEP convene a stakeholder group to offer input on how best to provide the information, and to review and comment on options and work products.[99]

b. TEP

TEP believes that the costs incurred to meet the EE Standard should continue to be recovered through the DSM Surcharge. TEP argues the current approach increases transparency to customers about EE costs, which otherwise would be lost if the costs were lumped into base rates. TEP also notes that this approach is consistent with the Commission's recent decision in the UNSE rate case.[100] Ultimately, TEP notes that a deviation from the current practice should be considered a policy decision for the Commission.

c. Staff

Staff believes that the costs for EE and DSM should continue to be collected through the DSM surcharge.[101] Staff asserts that by continuing with the DSM surcharge as currently employed, there is more transparency for the customer. In addition, Staff believes that if the EE or DSM program costs are included in base rates, it may take a rate case in order to exclude excess program costs.[102]

3. TORS Assets Included in Rate Base

a. EFCA

EFCA did not oppose the Settlement Agreement per se, but raised the question of whether the utility's investment in the TORS program should be included in rate base, which impacts the Settlement's rate base finding. In its Application, TEP included a $16,000 investment associated with one TORS installation in its rate base as part of this Application.

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[99] SWEEP/WRA/ACAA Opening Brief at 18.
[100] *See* Decision No. 75697 (August 18, 2016) at 13.
[101] Staff Reply Brief at 3.
[102] *Id.*; Tr. at 2869.

EFCA argues that the TORS Program may not be included in rate base unless or until it is demonstrated that the program is prudent.[103] EFCA argues that prior to including the Company's TORS assets in rate base, Staff was supposed to perform a prudency review.[104] Staff did not perform a prudency review of the TORS asset, and EFCA asserts that if Staff had conducted such review, it would have concluded that the investment in the TORS program was imprudent because there are lower-cost alternatives and the TORS program is wholly unnecessary.[105] EFCA states that the TORS program is significantly more expensive than other alternative means of obtaining Renewable Energy Credits ("RECs") for REST Rule compliance.[106] Moreover, EFCA argues that TEP doesn't even need to obtain additional RECs through the TORS program for REST compliance because the Commission has granted waivers and there is no reason to believe such no-cost waivers won't be granted in the future based on the amount of DG on the system.[107]

Thus, because there are lower-cost alternatives to the TORS program and the TORS program is unnecessary, EFCA recommends that the Commission should not only deny the Company's requested rate base of the TORS program, but should discontinue the program in its entirety because future investment will continue to be imprudent.

In Decision No. 74884, the Commission ordered that TEP "ensure that the cost of the utility-owned residential distributed generation program is similar to that of third-party programs." EFCA claims the prudency review and cost-parity provisions are intended to protect ratepayers, but that the Company has proposed changes to rate design that will substantially affect net metering customers, has not discussed how the changes will affect cost parity, and has failed to provide a cost-benefit analysis to support its discussion of the TORS program.

EFCA argues that the Commission's recent Decision in TEP's 2016 REST Implementation Plan

[103] EFCA Opening Brief at 20; EFCA Reply Brief at 19.
[104] Decision No. 74884 at 21. The Commission ordered: "[t]he Commission's approval of this pilot program should not be viewed as pre-approval for rate-making purposes in a future rate case. No determination of prudency or determination of rate base treatment for ratemaking purposes is being made at this time. Such determinations will be made during the rate case in which TEP requests cost recovery of this project."
[105] EFCA Opening Brief at 21.
[106] *Id.*; EFCA states the TORS program costs \$2.13 to \$2.20 per watt, but that TEP could have obtained RECs for 10 cents a watt or less.
[107] *Id.*

provides additional basis to deny the Company's proposal to rate base its TORS program.[108] In that Decision, the Commission concluded that: (1) the Commission cannot yet determine the reasonableness of the TORS program; (2) any claimed extra benefits of the TORS program other than the addition of renewable resources is speculative; (3) it is premature to authorize the expansion of the TORS program; and (4) Staff believes the RCS is a less expensive way to obtain RECs for REST compliance.[109]

b. <u>TEP</u>

TEP states that at the end of the test year it had installed and was operating one $16,000 TORS system pursuant to the pilot program approved in Decision No. 74884, and that the system is used and useful and providing energy to TEP's customers. However, TEP asserts the amount at issue in this case related to TORS is immaterial given TEP's $2 billion rate base, and has no impact on any rate or charge. TEP states that it understands that the remaining $9,984,000 portion of the TORS program may be subject to a prudency review in TEP's next rate case.[110]

c. <u>Staff</u>

Staff does not dispute that Decision No. 74884 provides that a determination of prudency of the TORS pilot program "will be made during the rate case in which TEP requests cost recovery of this project."[111] Staff notes that the scope of a prudency review is determined on a case-by-case basis and can include various types of actions, including a determination of whether everything is working as it should, the existence of cost overruns or inefficiencies, project-specific inquiries, and whether or not incurred costs were inefficient and/or unnecessary, but that there is no general yardstick or guide for conducting a prudency review.[112]

In this case, the amount of the TORS program included in rate base is $16,641 out of a total program of $10 million. Staff submits that a prudency review does not involve evaluating every single utility asset, and that a review of 0.0016 percent of the entire proposed program would be a costly endeavor with little benefit, as conducting a prudency review on such a minute portion of the proposed TORS program would not elicit a true determination of whether TEP's actions resulted in inefficient

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[108] EFCA Reply Brief at 19; Decision No. 75815 (November, 22, 2016).
[109] EFCA Reply Brief at 19.
[110] TEP Reply Brief at 7.
[111] Decision No. 74884 at 21.
[112] Staff Reply Brief at 12, EFCA Opening Brief at 20; Tr. at 1952-1953.

and/or unnecessary costs. Furthermore, Staff believes that a review of assets valued at $16,000 would be a waste of Commission resources. Staff believes that once the program is more fully installed, a prudency review would better serve its purpose. Staff submits "that the lack of a prudency review of the $16,641 installed TORS program should not prevent its inclusion in rate base under the present circumstances," and suggests that EFCA's recommendation is "absurd" given the fact that TEP has a FVRB of $2.8 billion, and that the TORS program is a pilot that the Commission approved with significant reporting requirements.[113]

D. Analysis and Conclusions Regarding Settlement Agreement

The proposed Settlement Agreement only resolves the revenue requirement portion of TEP's Rate Case. Although it was signed by only 11 of the 30 parties in this proceeding, those 11 represent a variety of interests, including large industrial customers, residential ratepayers, and environmental interests. Only the DOD took issue with one of the foundations of the Agreement.

The Settlement Agreements provides for a FVRB of $2.848 billion. This conclusion is $38 million less than Staff's recommendation, $266 million greater than RUCO's recommendation and $60 million less than the Company's original FVRB position.[114] No party, other than EFCA which opposes including TORS assets in rate base, objected to rate base balances in the Settlement. Given the pre-Settlement testimonies, the Settlement Agreement's position on rate base is reasonable and should be adopted.

We take no position at this juncture about the propriety of including TORS assets in rate base. The Commission approved the TORS program as a $10 million pilot project in the belief that the public interest would be served by exploring how such a program could benefit Renewable Energy Standard Tariff ("REST") compliance. The $16,000 TORS asset included in the $2.0 billion OCRB approved as part of the Settlement is immaterial to the determination of the revenue requirement or rates. In TEP's next rate case the TORS pilot project should be fully implemented, and at that time, we will determine if inclusion of those assets in rate base is appropriate. We concur with Staff that to require a prudency review of one TORS asset would not have been an efficient use of Commission resources

[113] Staff Reply Brief at 13.
[114] The specific rate base adjustments are set forth in Attachment A to the Settlement Agreement.

and would not have provided useful information on the entirety of the TORS program. Our decision to defer a finding on whether or not TORS assets should be included in rate base should not be seen as precedent for their ultimate inclusion.

Given the above, we find that a FVRB of $2,839,115,716, which is the average of the agreed OCRB and RCND rate base, is fair and reasonable.[115] This amount is $4,870,138 less than the figure included in the Settlement Agreement.

Based on a Fair Value Rate of Return of 5.35 percent, the Settlement Agreement provides for an $81.5 million non-fuel base rate increase, resulting in a $714,022,900 total non-fuel revenue requirement.[116]This reflects an 8.8 percent increase over adjusted test year revenues of $921,672,222. Because the corrected FVRB does not impact the agreed OCRB, and the rate of return on the difference between FVRB and OCRB is only 1.0 percent, the revenue impact of the correction is only $79,008. This amount is *de minimis* in the context of the agreed non-fuel revenue requirement increase of $81.5 million. Accordingly, we approve the agreed-upon revenue increase of $81.5 million set forth in the Settlement Agreement.

The $81.5 million increase is $44.3 million less than the $125.8 million that the Company originally requested.[117] It is $32.1 million greater than Staff's position in Direct Testimony, $64.1 million greater than RUCO's direct case recommendation, and $5.5 million greater than DOD's direct case. The operating expense adjustments agreed to in the Settlement are set forth in Attachment A thereto. The Settlement's proposed non-fuel increase is premised on a capital structure consisting of 49.97 percent long-term debt and 50.03 percent equity, a FVROR of 5.34 percent, which is based on a return on equity of 9.75 percent, and embedded cost of long-term debt of 4.32 percent, which results in a WACC of 7.04 percent. The rate of return on the fair value increment in the Settlement Agreement is 1.0 percent.

DOD believes that a 9.75 percent COE and return on the fair value increment of 1.0 percent are too high, and that the actual test year end capital structure consisting of 48.69 percent common equity

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[115] Final Schedule B-1.
[116] Ex TEP-1 Settlement at ¶2.1.
[117] Ex TEP-23 Dukes RJ at 2-3.

and 51.31 percent long-term debt should be utilized. DOD's recommended COE is 0.25 percent less than the Settlement Agreement.

The Settlement utilizes the actual test year capital structure, adjusted for the retirement of bonds that occurred shortly after the test year. The evidence supports the conclusion that TEP was obligated to redeem the bonds and that the redemption process was in place prior to the end of the test year. The pro forma adjustment represents a known and measurable change and warrants the use of the Settlement's agreed capital structure.

DOD criticizes certain assumptions in the Company's COE analysis, but the Settlement Agreement reflects a COE that is 0.25 less than the Company's rebuttal position and 0.6 percent less than the Company's original request. The agreed 9.75 percent COE is 0.05 percent higher than DOD's recommended cost based on the DCF method. The evidence shows that the Settlement's proposed 9.75 percent cost of equity is within the range of authorized equity returns for vertically integrated utilities in the proxy group which in 2015 ranged from 9.3 percent to 10.3 percent, with a median of 9.70 percent.[118] The Settlement's cost of equity is .25 percent higher than that recently approved for TEP's sister company UNSE, but TEP owns a much larger fleet of generation assets that still consists of a resource mix comprised 50 percent of coal, which exposes TEP to greater risk than faced by UNSE.[119] The Settlement Agreement's 9.75 percent COE is reasonable under the circumstances of this case.

DOD believes that the difference between the OCRB and RCND represents cost free capital, and that there should not be an additional return included for this fair value increment.[120] As an alternative, DOD utilized its underlying assumptions but applied the Company's method of determining the fair value increment, to compute a fair value increment return of 0.46 percent.[121] Staff has argued in this case, that the concept of cost of capital is designed to apply to OCRB, but that when the concept of FVRB is incorporated, the link between rate base and capital structure is broken, as the amount of FVRB that exceeds OCRB is not financed with investor-supplied funds, and it could be

[118] Ex DOD-4 Gorman Surr at MPG-24.
[119] Tr. at 368; Ex TEP-24 Sheehan Dir at 2.
[120] Ex DOD-3 Gorman Dir at 70-71. DOD argues that the Net Operating Income should be set by either an original cost or a fair value rate-setting methodology. According to DOD, in the OCRB Rate of Return the expected growth rate in asset values is included in the rate of return and in a fair value methodology, expected growth in the value of assets is picked up in the growth to the rate base itself, and not rate of return.
[121] *Id.* at MPG-21.

argued has no cost.[122] However, Staff prepared an alternative analysis for the fair value increment based on a risk-free rate, and recommended a fair value rate of return of 0.7 percent.[123]

In recent rate cases, the Commission has authorized returns that recognize the methodology utilized by the Company and Staff to provide a positive return for the fair value increment. The Settlement Agreement adopts a fair value increment rate of return that is 0.3 percent greater than Staff's recommendation and 0.42 percent less than originally proposed by TEP. It is based on a methodology utilized by the Commission in the past and is not unreasonable as a negotiated resolution.

Under the totality of circumstances in this case, including the rate design issues resolved later, we find that a cost of equity of 9.75 percent is reasonable.

SWEEP is the only party that proposed to include the costs of the Company's authorized EE and DSM programs in base rates. While we do not disagree that EE is an important resource for the Company, we have not been presented with a compelling reason to change the current structure for recovering their costs.

We find that the terms of the Settlement Agreement were the result of open and transparent discussions, and when corrected to reflect the appropriate FVRB, are fair and reasonable. Thus, we approve the Settlement Agreement as corrected.

We also believe that customer education and transparency in utility operations and ratemaking is important. SWEEP's proposal to communicate information about resource mix and costs is helpful to that process. TEP did not oppose the idea. Having the information available in a simple format as suggested by SWEEP should not be costly. Thus, we direct TEP to file, within 120 days of the Order in this proceeding, a proposal to provide information to customers on the ratepayer costs of major energy resources via the web, and how to communicate with consumers about accessing the data.

III. Revenue Allocation

A. TEP

TEP states that one of its goals in this rate case is to reduce interclass subsidies by bringing revenue recovery from each class closer to its actual cost of service, however, in conformance with the

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[122] Ex S-3 Parcel Dir at 43-45.
[123] *Id.* at 47-49.

principle of gradualism, the Company did not propose a revenue allocation that would bring complete class parity under the CCOSS. As the revenue requirement was reduced and other parties expressed their positions on revenue allocation, TEP revised its initial proposal, ultimately accepting much of the structure of Staff's allocation methodology, which included not decreasing rates for any customer class.[124] However, TEP allocates less to the Residential, LPS and 138kV classes than Staff.

TEP prepared the following comparison of various allocation recommendations:[125]

Class	Current Adjusted TY Revenues (000's)	TEP (000's)	Staff/RUCO (000's)	AECC/Freeport/NS[126] (000's)
Residential	$432,072	$51,880	$54,501	$76,683
SGS	269,039	(3,947)	(10,666)	(8,553)
MGS/LGS	114,102	27,795	29,158	18,278
LPS	134,106	4,245	5,917	3,529
138kV	0	615	1,999	(2,091)
Lighting	4,971	913	591	1,101
Sub Total	954,290	81,501	81,500	88,947
Rider 14 Rev	--			(7,471)
Total	954,290			81,476

Although all of the proposed revenue allocations move toward parity, TEP claims that its proposal provides the best opportunity to reach parity in the next rate case. TEP believes that how quickly to move to parity is a policy decision for the Commission.[127]

B. AECC/Freeport/NS

AECC/Freeport/NS argue that TEP's and Staff's proposed revenue allocations do not produce just and reasonable rates because they retain significant interclass subsidies. AECC/Freeport/NS argue that their proposed revenue allocation among the various rate classes best serves the public interest because it: (1) reduces the inter-class subsidies that impede economic development and sustainability; (2) brings all customer classes closer to rate parity and a unitized rate of return ("UROR") of 1.00, while still adhering to the concept of "gradualism"; and (3) corrects certain distortions in TEP's cost-of-service study, providing the Commission with a more accurate basis on which to structure a proper

[124] Ex TEP-31 Jones Rebuttal at 11; Ex TEP-32 Jones RJ at 4-5.
[125] TEP Reply Brief at Attachment A.
[126] TEP states that the AECC/Freeport/NS revenues reflect their recommendations under their buy-through option 1.
[127] TEP Reply Brief at 8.

rate design.[128] These parties note that although TEP expressed a goal of moving revenue recovery closer to cost of service, as TEP revised its position in response to a lower revenue requirement, and accepted much of Staff's allocation structure, its allocation proposal became more removed from its CCOSS.[129]

AECC/Freeport/NS provided the following illustration of their recommended allocations:[130]

Class	Current Adj TY Sales Revenues	Proposed Sales Revenues	Proposed $ Change	Proposed % Change
Residential	$402,568,874	$475,866,481	$73,297,608	18.2%
General Services	211,889,211	238,229,710	16,340,499	7.4%
LGS	144,368,117	139,727,495	(4,640,621)	-3.2%
LPS	91,514,743	91,917,799	403,056	0.4%
138 kV	30,466,830	27,501,859	(2,964,971)	-9.7%
Lighting	4,638,212	5,713,602	1,075,390	23.2%
Sub-Total	895,445,987	978,956,947	83,510,960	9.3%
Experimental Rider- 14 Reserve		(7,470,705)	(7,470,705)	
Total	895,445,987	971,486,241	76,040,254	8.5%

According to AECC/Freeport/NS, the inter-class subsidies included in its, TEPs and Staff's allocation proposals are as follows: [131]

TEP[132]

Customer Class	Proposed Margin Revenue	Subsidy Paid/(Received)
Residential	327,768,312	(65,280,282)
General Services	180,501,853	31,096,260
Large General Services	96,255,565	24,576,959
Large Power Service	56,404,499	6,645,308
High Voltage 138kV[133]	17,177,856	4,246,566
Lighting	4,211,298	(1,260,450)
Total	682,319,384	24,361

Staff[134]

Customer Class	Proposed Margin Revenue	Subsidy Paid/(Received)
Residential	330,389,025	(62,659,569)
General Services	173,782,573	24,376,979
Large General Services	97,778,732	26,100,126

[128] AECC/Freeport/NS Opening Brief at 7.

[129] AECC/Freeport/NS Reply Brief at 1-2.

[130] Ex AECC-10 Higgins Surr at 18 (based on initial AECC proposed Buy-Through Option). AECC/Freeport/NS and TEP do not utilize the same starting test year revenues because Mr. Higgins adjusted the test year revenues to reflect the change in the fuel cost that occurred after the test year.

[131] AECC/Freeport/NS Opening Brief at 9. AECC/Noble Solutions states that they modified Staff's Proposed GS, LGS, LPS and 138 kV Sales revenue to capture the impact of adjustments to current revenues to reflect the impact of load migration among classes.

[132] Based on Ex TEP - 32 Jones RJ, Exhibit CAJ-RJ-1, Sch H-2-2.

[133] Freeport's Sierrita Mine is the only member in the 138kV class.

[134] Based on Ex S-12 Solganick Surr, Exhibit HS-6 & HS-6 workpaper (Confidential)

Large Power Service	57,892,333	8,133,143
High Voltage 138kV	18,562,241	5,630,951
Lighting	3,890,251	(1,581,498)
Total	682,295,154	131

AECC

Customer Class	Proposed Margin Revenue	Subsidy Paid/(Received)
Residential	352,570,805	(40,477,788)
General Services	175,896,150	26,490,557
Large General Services	86,738,121	15,059,516
Large Power Service	49,759,191	0
High Voltage 138kV	12,931,290	0
Lighting	4,399,465	(1,072,284)
Total	682,295,023	--

AECC/Freeport/NS state that their analysis shows that Freeport, the only member of the 138kV class would pay a subsidy of over $4.21 million in margin revenue under TEP's proposal, and would pay a subsidy of $5.63 million under Staff's proposal. AECC/Freeport/NS argue that either subsidy is overly burdensome and does not produce a "just and reasonable" rate for Freeport. In addition, the tables show that the LGS Class customers would collectively pay between $24.58 million to $26.10 million under TEP's or Staff's proposals, while the LPS customers would collectively pay subsidies between $6.65 million to $8.13 million annually. They also show the Residential Class would receive $62.66 million of annual subsidies under Staff's proposal and $65.28 million under TEP's proposal.

AECC/Freeport/NS assert that no party provided any justification for these subsidies, and that although Staff and TEP have acknowledged that the Commission should be working to eliminate subsidies entirely, their proposals fall substantially short of meaningful movement towards rate parity. AECC/Freeport/NS state that under Staff's revenue allocation proposal, Freeport would pay rates producing a 22.25 percent rate of return annually, when the authorized overall rate of return is 7.19 percent, resulting in a UROR for Freeport of 3.093.[135]

AECC/Freeport/NS assert that neither TEP nor Staff explain why the Residential Class should not pay more based on the CCOSS, and they argue that Staff presented no evidence why the public interest is served by waiting so long to move all rate classes to rate parity, and that Staff's allocation methodology is arbitrary. They state:

> Under Staff's first principle, individual rate classes should be "gradually"

[135] Ex S-32 Solganick Surr, Exhibit H-6.

> moved toward a UROR over one or more rate cases depending on the frequency of rate cases and the distance of the class' UROR from 1.000. However, there is no standard in applying this principle, no relationship between the frequency of rate cases to the rate disparity among the classes, or no algorithm for Staff to determine how 'gradually' to move rate classes closer to parity. Instead, the determining factor appears to be how much revenue is available to allocate.[136]

AECC/Freeport/NS also argue that the proposition that acquisition of the Gila River Generating plant warrants a rate increase for all rate classes, irrespective of the CCOSS, is unreasonable and not founded on facts. AECC/Freeport/NS argue that rates should be based on facts, not perception and that the facts demonstrate that for years large customers have been paying not only for the resources needed to serve them, but also for the costs of serving other rate classes.[137] They argue that denying the 138 kV class a rate decrease deprives that class of the benefits of the lower costs that they bargained for by not using the distribution system.

AECC/Freeport/NS assert that parties such as Freeport, Kroger and Wal-Mart presented evidence that demonstrates that large subsidies and TEP's high electric rates have a detrimental effect on economic development and sustainability, and that the Commission should consider the societal benefits that these customers bring through economic stimulus, job creation and tax base as factors in considering the broad public interest.

AECC/Freeport/NS claim that Freeport's Sierrita Mine alone produced $250.7 million in economic benefits to Pima County in 2015, and $343.6 million for the state of Arizona as a whole.[138] AECC/Freeport/NS acknowledge that the recent cut-backs at the Sierrita mine are "based in part" on the falling price of copper, but they assert that the ability to continue or expand operations in a highly competitive market is based on several factors, including power costs, which are Freeport's second highest operating expense after labor.[139] AECC/Freeport/NS assert that in the competitive environment in which it operates, Freeport can ill-afford to pay between $4.2 million and $5.6 million in rate subsidies each year.

AECC proposed to set the revenue requirement for both the LPS and 138 kV classes at cost, and to reduce the allocation of the LGS and GS classes such that the rates for these classes is no more

[136] AECC/Freeport/NS Reply Brief at 3; *citing* Tr. at 2399.
[137] AECC/Freeport/NS Reply Brief at 3.
[138] AECC/Freeport/NS Opening Brief at 10.
[139] *Id.* at 11; Tr. at 1706; Ex AECC-14 McElrath Surr at 6.

than 12.5 percent above the cost of service.[140] AECC/Noble Solutions assert that the URORs for each class would move closer to parity, set forth as follows:

Rate Class	Proposed UROR
Residential	0.56
General Services	1.77
Large General Services	1.94
Large Power Service	1.00
High Voltage 138kV	1.00
Lighting	0.25
Total	1.00

Under AECC/Freeport/NS's proposal, larger customers would receive a rate decrease, and although residential customers would experience a larger rate increase (18.2 percent) than proposed by TEP (11.9 percent) or Staff (12.7 percent), they would still receive over $40 million in rate subsidies annually from other rate cases.[141] AECC/Freeport/NS assert that their proposal represents meaningful gradualism. AECC/Freeport/NS note that the Company's ultimate revenue allocation is markedly different than what it included in its original application as a way to compromise on certain rate design issues. AECC/Freeport/NS argue that "the need for compromise outside a global settlement cannot serve as justification for a revenue allocation that, like Staff's, fails to produce "just and reasonable" rates for commercial and industrial customers."[142]

C. **Wal-Mart**

Wal-Mart urges the Commission to attempt to eliminate the subsidies between TEP's customer classes, because it will create more fair, cost-based rates, and will send proper price signals that encourage more efficient use of the system.[143] Wal-Mart argues that TEP's Rejoinder position on revenue allocation results in excessive subsidization by the LGS class.[144] Wal-Mart notes that TEP's proposed revenue allocation has an overall rate of return on rate base of 7.43 percent, but the LGS Class has a rate of return of 18.23 percent.[145] Wal-Mart recommends that the Commission adopt a

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[140] Ex AECC-10 Higgins Surr at 17 - 18
[141] AECC/Freeport/NS Opening Brief at 12; Ex AECC-12.
[142] AECC/Freeport/NS Opening Brief at 13. AECC/Freeport/NS disagree with Staff's basic premise that no customers should receive a rate decrease in this proceeding, and asserts that it is not based on a Commission policy and ignores the cost-of-service data.
[143] Wal-Mart Opening Brief at 2. '
[144] Revised Schedule G-2 filed by Company on December 4, 2016.
[145] Wal-Mart Opening Brief, Appendix A, line 35, columns A and D.

revenue allocation that proportionately assigns the subsidy burden across the subsidizing classes at the Company's originally proposed revenue requirement, and allot one-half of the $44.3 million revenue reduction resulting from the Settlement Agreement to directly reduce the subsidies at equal percentages across all the subsidizing classes. Further, the remainder of the revenue reduction should be applied across all rate classes in equal percentages, reducing the increase for all classes.[146] In its Surrebuttal Testimony, Wal-Mart recommended the following allocations:[147]

	Total	Residential	SGS	LGS	LPS/138kV	Lighting
Non-fuel Revenue	$714,022,900	$353,744,533	$185,897,391	$88,451,564	$81,279,642	$4,649,771

Wal-Mart recognizes that its recommendation does not eliminate the inter-class subsidies, and that the Residential Class would still receive a subsidy of approximately $72 million. However, Wal-Mart asserts that its proposed allocation equitably shares the burden of the subsidy while being minimally burdensome to the subsidizing classes.[148]

Wal-Mart argues that a movement toward cost of service that implements more gradual, pre-determined annual steps to eliminate the subsidies would address both inequities in current rates and rate shock.[149] Thus, in addition to adopting a revenue allocation that more closely reflects the CCOSS, Wal-Mart proposed a new revenue support rider ("RSR") to reapportion the revenue collection between classes each year until inter-class subsidies are eliminated.[150] Wal-Mart states that the RSR would not affect the authorized revenue requirement and would be revenue neutral for TEP. The RSR would be a credit applied to the bills of each subsidized class and a surcharge on the bills of each subsidizing class. Each year there would be pre-determined reduction to the credits and surcharges, resulting in the elimination of the existing subsidies. Wal-Mart claims that the RSR would result in more palatable annual reductions to the subsidies, rather than addressing subsidies through less frequent rate cases where the impact would be more significant.[151]

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[146] Ex Wal-Mart-2 Tillman Dir Rate Design at 14; Ex Wal-Mart-3 Tillman Surr at 5-6; Tr. at 1818.
[147] Ex Wal-Mart-3 Tillman Surr at 6.
[148] *Id.*
[149] Wal-Mart Opening Brief at 4.
[150] Ex Wal-Mart-2 Tillman Dir at 15; Tr. at 1818-1819.
[151] Tr. at 1822, 1837; Wal-Mart's proposed POA for the RSR is attached to Ex Wal-Mart-3 Tillman Surr at Exhibit GWT-S-3.

D. Kroger

Kroger accepts the Company's revised rate spread proposal, specifically, the allocation to the LGS rate class.[152]

E. DOD

DOD notes that there was general agreement among the parties that the average and excess methodology used for the CCOSS was appropriate, and given the high summer demands relative to demands in other months, that the peak portions of the CCOSS should be based on the summer peak months.[153] DOD also states that there was general agreement that the LPS class was being charged too much in relation to cost of service and that it should receive a decrease, or at least an increase less than the system average increase. DOD notes that in its Direct Testimony, the Company proposed a 16.2 percent increase for the Residential class and a 2.4 percent decrease for the LPS class, but with each round of testimony, the allocations became less cost-based. DOD argues the Company's Rejoinder position is unreasonable as it continues large subsidies. DOD recommends to retain the Residential class increase at the level originally proposed by TEP (regardless of the overall increase ultimately granted) and to "proportion down" the revenues to be received from the other customer classes on an equal basis. Thus, DOD recommends the following revenue allocations (based on the Settlement's $81.5 million increase, and on DOD's recommended increase of $67.3 million):[154]

Settlement Increase of $81.5 million (in millions)

Class	Adj TY Revenue	Revenue after Increase	Proposed Increase	Percent Increase
Residential	$404.6	$470.0	$65.4	16.2%
General Service	249.2	244.3	(4.9)	-2.0%
Lg Gen, Service	119.2	148.9	29.7	25.0%
Lg Power Service	131.7	121.9	(9.9)	-7.5%
Lighting	4.7	5.7	1.1	23.1%
Total	909.3	990.8	81.5	9.0%

DOD Proposed Increase of $67.3 million (in millions)

Class	Adj TY Revenue	Revenue after Increase	Proposed Increase	Percent Increase
Residential	$404.6	$470.0	$65.4	16.2%
General Service	249.2	237.6	(11.6)	-4.6%
Lg Gen, Service	119.2	144.9	25.7	21.5%
Lg Power Service	131.7	118.5	(13.2)	-10.0%

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[152] Kroger Opening Brief at 3.
[153] DOD Opening Brief at 28.
[154] DOD Opening Brief at Attachment A (as presented, rounding not adjusted); DOD Reply Brief at 4.

Lighting	4.7	5.6	0.9	19.7%
Total	909.3	976.6	67.3	7.4%

DOD argues that its proposed allocation makes meaningful progress toward cost of service based rates, but includes a healthy dose of gradualism, and that the above average increase to the Residential class is essential to close the gap.

DOD argues that Staff's principles (that the percentage increase for any class should not exceed 150 percent, or be less than 50 percent, of the system average) are arbitrary and unreasonable under the current circumstances faced by TEP's customers.[155] Because the Residential Class is so far from cost of service with a negative rate of return, DOD argues that an increase somewhat higher than might otherwise be considered is necessary to make meaningful movement to cost of service and to relieve the burden on the large customer classes.[156]

F. <u>Staff</u>

Staff supports the Company's proposal to switch from the Peaks and Average allocator used in the last rate case to the Average and Excess Demand ("AED") method and its proposal to create the new MGS and 138 kV classes. Staff agrees with the Company that the CCOSS is used as a guide in the allocation of revenue and rate design. Staff was critical of the Company using the AED in conjunction with a 4 Coincident Peak ("4CP"), and the Company revised the CCOSS to incorporate the AED-NCP allocator and changes to meter and customer allocations. These changes increase the allocation of costs to lower load factor classes compared to the Peaks and Average methodology used in the last rate case.

Staff notes that the 20 percent increase in distribution plant and 47 percent increase to net production plant, as well as the change to the AED-NCP allocation methodology, magnified the impact of the revenue impact on the classes. As a result, Staff recommended using the CCOSS as a general guide, and following the principles of gradualism, in allocating revenue recovery among the classes rather than strictly adhering to the CCOSS results.[157] Staff believes that the Commission should consider the relative position of the classes along with qualitative issues such as economic conditions for consumers, the business climate for commercial and industrial customers, and past practices as it determines revenue allocations. Staff utilized the following criteria to guide its recommended revenue

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[155] DOD Reply Brief at 5.
[156] *Id.*.
[157] Staff Opening Brief at 9.

allocation: (1) the individual rate classes should be gradually moved toward a UROR of 1.000 over one or more rate cases depending on the frequency of rate cases and the distance of the class' UROR from 1.000; (2) there should be an upper bound of 150 percent for any class' percentage increase in revenue compared to the overall percentage increase in revenue; and (3) there should be a lower bound of 50 percent for any class' increase compared to the overall increase.[158] Furthermore, Staff believes consideration should be given to the Company's purchase of the combined cycle Gila River plant. Staff states the plant was purchased to stabilize energy costs, which benefits all customers, and that it would send a confusing message about the plant expenditure and be inappropriate to reduce rates for any customer class.

Based on Staff's modeling, the updated CCOSS, the principles discussed above, the purchase of the Gila River combined cycle plant, change in allocation methodology, and the relative impacts between classes, Staff recommends the $81.5 million revenue requirement be allocated by increasing the Residential, LGS and Lighting classes 50 percent of the amount to reach parity and increasing all other classes by $23.3 million. Under Staff's approach, the Residential Class receives 66.9 percent of the overall $81.5 million revenue increase. Staff' recommends the following allocations:[159]

Class	Adjusted TY Revenues[160]	Proposed Revenue Incr	% Change	Class % of Increase
Residential	$432,072,072	$54,501,050	12.6	66.9
General Service	$269,038,109	15,420,669	5.8	18.9
LGS	$114,101,742	3,070,470	2.7	3.8
LPS	$134,105,708	5,917,284	5.9	7.3
138kV		1,990,080		2.4
Lighting	$4,970,743	591,468	11.9	0.7
Total	$954,289,374	81,491,021	8.5	100

[158] *Id.* at 10.
[159] *Id.* at 11.
[160] Final Schedules at G-1 sheet 1.

Staff responds to Wal-Mart's revenue rider proposal with the observation that the proposal presumes that the relative positions of the customer classes would not change over the period due to DG penetration, EE, and the growth or loss of customers.[161] Additionally, Staff states the rider does not take into account that sales will change from the test year. Thus, Staff asserts that an adjustment and reconciliation methodology and Plan of Administration must be developed at the implementation of the plan and that the Commission should not move forward on this concept without a detailed debate and understanding of its effects and supposed benefits.[162]

G. <u>Analysis and Conclusion Regarding Revenue Allocation.</u>

The CCOSS indicates that under current rates there are significant inter-class subsidies, with the large power users subsidizing the residential class. According to the Revised CCOSS, in the test year, the overall Company rate of return on OCRB was 6.57 percent, with the Residential Class rate of return at 0.94 percent, the General Service Class rate of return at 21.33 percent, the LGS Class with a rate of return of 3.50 percent, the combined LPS/138 kV Classes with a rate of return of 10.94 percent, and the Lighting Class with a return of 2.96 percent. These results support a higher proportionate allocation of the revenue increase to those classes below the overall return, i.e. Residential, LGS and Lighting.

To allocate the $81.5 million increase evenly across classes would perpetuate existing inequities, burdening the subsidizing classes. However, to move all the rate classes to a UROR of 1.000 would cause unreasonable rate shock, as Mr. Solganick's analysis shows that to bring all class to parity, the Residential Class would incur a 39.5 percent increase in margin revenues.[163]

While we do not determine here that a UROR of 1.0 for all customer classes is necessary for just and reasonable rates or an ultimate goal, we do recognize that the current rates produce substantial interclass subsidies, and that a reduction in the amount of subsidies is in the public interest. Any reduction in allocation to one class, of necessity increases the allocation to another in order to produce the same overall revenue increase. In our attempt to move toward more equitable revenue recovery

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[161] Ex S-12 Solganick Surr at 25. Staff Reply Brief at 6.
[162] Staff Reply Brief at 6.
[163] Ex S-13 Solganick Surr at HS-6. The 138 kV class would see a decrease of 19.7 and the GS class would see a decrease of 20 percent.

without overly burdening an individual customer class, and considering the entirety of circumstances, we find that the following allocation of the $81.5 million non-fuel revenue increase is just and reasonable. This allocation adopts Staff's recommendation for the Residential Class of $54.5 million and employs TEP's proportionate allocations for the remaining $27 million.

Class	Adj. TY Rev[164]	Increase	% Incr.	% of total increase
Residential	$432,072,000	$54,501,000	12.6%	66.87%
SGS	269,039,000	(3,598,000)	-1.34%	-4.41
MGS/LGS	114,102,000	25,335,000	22.20%	31.09%
LPS	134,106,000	3,869,000	3.3%[165]	4.75%
138 kV	0	561,000		0.69%
Lighting	4,971,000	832,000	16.74%	1.01%
Total	954,290,000	81,500,000	8.54%	100.0

Wal-Mart proposed eliminating the subsidies paid by commercial and industrial classes over eight years through a "subsidy mitigation plan"[166] The plan would bring all classes to rate parity under the cost of service study by eight annual rate adjustments. Under this plan, residential customer bills would go up every year for eight years. We do not find the RSR is in the public interest because it is based on test year positions which are unlikely to remain static and would result in higher Residential rates without taking account of changed circumstances.

IV. Rate Design

A. Residential and Small General Service

Currently, TEPs residential and small commercial customers are served by a simple two-part rate comprised of a basic service charge ("customer charge" or "BSC") and energy charges based on usage. TEP claims that the two-part rate design does not reflect the way costs are incurred to serve these customers, but was justified in the past because these customers had relatively similar usage

[164] Final Schedule G-1 at 1.
[165] Combined LPS/138 kV
[166] Tr. at 1831.

levels and patterns, and because meters capable of measuring demand were prohibitively expensive.[167] TEP asserts that today, customer access to distributed energy resources and demand management opportunities, are causing growing inequities that are exacerbated by rates that have become more detached from cost causation. TEP states that a customer's individual kWh consumption does not reflect the fixed costs they impose on the system, as customers with low usage due to DG or a seasonal or vacant home, require significant plant and fixed costs to be connected to the grid, but under the current two-part rate, contribute little to the recovery of the fixed costs of serving them. TEP states that nearly one in three of its basic residential rate bills during the test year reflect a monthly usage of 400 kWh or less, and that it recovered only $10 to $33 in fixed costs per month from these bills, which is only a fraction of their share of the fixed costs ($87 per month) incurred to serve them. TEP states that it is proposing to change its residential and small general service rate structure in order to: (1) begin to address its customers' evolving use of the electric system; (2) better align rate design with cost causation and reduce inter- and intra-class inequities; (3) reduce the level of cross-subsidies among customers; and (4) enhance the Company's ability to recover its fixed costs.

TEP claims that its proposed rate design is a gradual approach to meet these goals and allocates approximately 40 percent of the revenue requirement increase for the Residential and SGS classes to the Basic Service Charge and 60 percent to volumetric rates. According to the Company, under its proposal, both the BSC and volumetric rates will increase, and TEP will still be recovering 83 percent of its fixed costs through volumetric rates for standard residential customers.[168] TEP believes that its proposed rate design comports with the Commission's acknowledgement in the UNSE rate case that the "the time is ripe for a more modern rate design" and that "outdated rate designs may contribute to under-recovery of fixed costs and may not adequately reflect cost causation."[169]

TEP argues that some parties' recommendations that oppose rate design changes to reduce the amount of fixed costs recovered through volumetric rates and even argue to recover more fixed costs through volumetric rates, exacerbate the current inequitable recovery of fixed costs and resulting cross-

[167] TEP Opening Brief at 19.

[168] All but $15 of $87. TEP Reply Brief at 14. TEP states that the percentage will be higher for other residential rate options with a $12 BSC. TEP states it will recover almost 92 percent of its fixed costs for SGS customers through volumetric charges under its proposal.

[169] Decision No. 75697 (August 18, 2016) at 65 and 117. TEP Reply Brief at 14.

subsidies.[170] TEP asserts that the mismatch between costs and revenues leads to inappropriate cost signals and the inability to recover its authorized revenue requirement due to declining kWh use per customer.

For residential customers, TEP is proposing four rate options: (1) a basic two-part rate; (2) a two-part time-of-use ("TOU") rate; (3) a basic three-part rate that includes a monthly BSC, a demand charge and a volumetric energy charge; and (4) a TOU three-part rate that is the same as the basic three-part rate except that the volumetric energy charges will be TOU-based.[171] TEP's proposed the following residential two- and three-part rates:[172]

Residential Service (TE-R-01)

	Current Rates	Proposed Rates	$ Increase	% Increase
Basic Service Charge Single Phase per month	$10.00	$15.00	$5.00	50%
Basic Service Charge Three Phase per month	$15.00	$20.00	$5.00	22%
Sum First 500 kWh	$0.056200	$0.063804	$0.007604	14%
Sum 501-1,000 kWh	$0.067200	$0.079600	0.012400	18%
Sum 1,001-3,500 kWh	$0.079800	$0.079600	-0.000200	0%
Sum > 3,500 kWh	$0.088200	$0.079600	-0.008600	-10%
Win First 500 kWh	$0.056200	$0.063804	0.007604	14%
Win 501-1,000 kWh	$0.065200	$0.079600	0.014400	22%
Win 1,001-3,500 kWh	$0.078100	$0.079600	0.001500	2%
Win > 3,500 kWh	$0.087100	$0.079600	-0.007500	-9%
Base Power Summer kWh	$0.035111	$0.035691	0.000580	2%
Base Power Winter kWh	$0.031532	$0.032608	0.001076	3%
PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Residential Service Demand (TE-RXXX)

[170] TEP Reply Brief at 14.
[171] TEP states all four rates are designed to recover similar amounts from the typical residential customer, and that for qualifying lost income residential customers, the Company will offer a Lifeline discount, and SGS customers will have similar rate options.
[172] Ex TEP-32 Jones RJ at CAJ-RJ-1 at 6.

	Current Rates	Proposed Rates
Basic Service Charge per month	N/M	$12.00
Demand 0-7 kW	N/M	$8.75
Demand >7 kW	N/M	$12.50
Sum kWh	N/M	$0.031740
Win kWh	N/M	$0.031740
Base Power Summer kWh	N/M	$0.035691
Base Power Winter kWh	N/M	$0.032608
PPFAC Charge kWh	N/M	$0.000000

Under the Company's proposed rate design and using its proposed revenue allocation, the bill increase for an average residential customer using a monthly average of 785 kWhs in the winter on a standard two-part rate is $8.41 per month, or 9.7 percent, from $86.78 to $95.19.[173] In the summer, a residential customer on the standard two-part rate with a monthly average of 1,150 kWhs, would see an increase of $7.79, or 5.9 percent, from $131.89 to $139.68.[174]

The Company proposes a rate structure for SGS customers that parallels the rate structure of residential service, except that current TOU periods would remain as they are in order to match other commercial classes. Under TEP's proposal, SGS customers could take service under a two-part rate, a two-part TOU rate, or a standard and TOU three-part rates. The BSC for the standard two-part rates would be $27 per month, which TEP states is below the minimum system cost for these customers.[175] The BSC for the other options would be $22. TEP argues that these changes should be approved for the same reasons as for the residential changes.[176]

TEP proposed SGS two- and three-part rates as follows:[177]

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[173] Ex TEP-32 Jones RJ, Exhibit CAJ-RJ-2 at 6.
[174] *Id.*
[175] Ex TEP-34 Smith Rebuttal at 9 and 10.
[176] TEP Reply Brief at 19.
[177] Ex TEP-32 Jones RJ at CAJ-RJ-1 at 7.

SGS

	Current Rates	Proposed Rates	$ Increase	% Increase
Basic Service Charge Single Phase per month	$15.50	$27.00	$11.50	74%
Basic Service Charge Three Phase per month	$20.50	$32.00	$11.50	56%
Sum First 500 kWh	$0.077000	$0.086250	$0.009250	12%
Sum > 500 kWh	$0.097800	$0.101100	0.003300	3%
Win First 500 kWh	$0.057000	$0.066300	0.009300	16%
Win > 500 kWh	$0.079000	$0.087300	0.008300	11%
Base Power Summer kWh	$0.035111	$0.035691	0.000580	2%
Base Power Winter kWh	$0.031532	$0.032608	0.001076	3%
PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

SGS Demand

	Current Rates	Proposed Rates
Basic Service Charge per month	N/M	$22.00
Demand 0-7 kW	N/M	$9.95
Demand >7 kW	N/M	$13.50
Sum kWh	N/M	$0.063890
Win kWh	N/M	$0.053890
Base Power Summer kWh	N/M	$0.035691
Base Power Winter kWh	N/M	$0.032608
PPFAC Charge kWh	N/M	$0.000000

TEP estimates that under its proposed rates, an average SGS customer using 1,340 kWhs would see an increase of $15.42, or 9.5 percent, from $161.75 to $177.17 in winter, and in summer the average SGS customer using 1,886 kWhs would see an increase of $8.94, or 3.3 percent, from $268.58 to $277.52.[178]

[178] Ex TEP-32 Jones RJ at CAJ-RJ-1 page 57. It is not clear whether or not the bill impacts for the SGS Class include the members of the class that will be migrated to the MGS Class. If they do, then the average impact for the remaining SGS

In addition to service rates, TEP proposed updated service fees.[179] The Company has no objection to the recommendations made by Staff regarding the service fees.[180] TEP notes there does not appear to be opposition to the revised service fees.

1. Residential Rates – BSC

a. TEP

TEP proposes a BSC of $15 for its standard two-part residential rate, and $12 for the other three rate options. TEP states that the BSC is designed to recover the costs incurred for meters, billing and collection, meter reading the service line or drop and "the other components" needed to form the minimum system.[181] TEP states that pursuant to its CCOSS, the minimum system cost is $15.03.[182]

TEP asserts that the uncontroverted evidence in this case establishes that the fixed monthly cost to serve the average residential customer is approximately $87.[183] TEP argues that the Minimum System approach provides customers with a more accurate price signal of the costs incurred to assure minimum and reliable service. TEP contends that coupling the new customer charge with the elimination of the top two tiers, reduces the intra-class subsidy related to recovering fixed costs. TEP believes this is important for transitioning to rates that meet cost causation and matching principles.[184] TEP asserts that even with its proposed residential increase from $10 to $15, the Company will still recover $72 per month of its fixed costs through volumetric rates for standard two part residential rates.[185]

TEP argues that the Basic Customer Method of determining the customer charge underestimates the unavoidable fixed system costs needed to serve a customer, and ignores the increasingly diverse use of the grid that makes recovery of fixed costs through volumetric rates inequitable.[186] TEP claims that concerns that increasing the BSC will reduce customer incentives to conserve energy are

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may be skewed by larger users who will no longer be members of the class, such that the average kWh usage of the remaining SGS class will likely be less than the current figures.

[179] Ex TEP-30 Jones Dir at Ex CAJ-3 (Proposed Tariff Sheet No 81).
[180] Ex S-10 Solganick Dir at 44-47; Ex TEP-31 Jones Rebuttal at 32.
[181] TEP Opening Brief at 22.
[182] Ex TEP-45 (updated Schedule G-6-1) at 2, line 24.
[183] Ex TEP-45 (updated Schedule G-6-1 at Sheet 1 of 1); TEP Reply Brief at 15.
[184] TEP Opening Brief at 23.
[185] TEP Reply Brief at 15; Ex TEP-45, Schedule G-6-1 (line 33)(fixed cost at $87); Ex TEP-32 Jones RJ, Ex CAJ-RJ-1, Schedule H-3, page 6 of 23 (setting forth monthly customer charges).
[186] TEP Opening Brief at 23.

misleading and exaggerated because the portion of the bill determined by volumetric rates only declines from 89 percent to 83 percent leaving plenty of incentive to conserve.[187] It argues that recommendations for a lower BSC would increase the mismatch of fixed cost recovery, pointing specifically to RUCO's proposal that would lead to more than 90 percent of residential customer fixed costs being recovered by volumetric rates.[188]

TEP adamantly denies that its goal is to collect all fixed costs through fixed charges, and asserts that the Commission has not required use of the Basic Customer method, and recently approved a BSC for UNSE that reflected the Minimum System Method.[189]

b. <u>RUCO</u>

RUCO recommends increasing the standard residential BSC from $10 to $13 per month, and a residential TOU BSC of $10 (a reduction from the current $11.50 per month). RUCO also proposes a three-tier volumetric rate design for residential customers. RUCO argues that its proposal has better support in the record, is based on the traditional cost of service methodology used by the Commission and most other states, and is fairer to the ratepayer.[190]

RUCO argues that the Company's proposed Minimum System method places more costs in the basic service charge than are actually incurred, and is therefore controversial, not cost based, and relies on a completely hypothetical distribution system.[191]

RUCO argues that Professor Bonbright, in his seminal treatise on principles of utility rates, rejects the minimum distribution system methodology. In <u>Principles of Public Utility Rates</u>, Second Edition, Professor Bonbright writes:

> But if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs for the reason just given, while it is also denied a place among the customer's costs for the reason stated previously, to which cost function does it then belong? The only defensible answer, in our opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs. And this is the disposition that it would probably receive in an estimate of long-

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[187] *Id.* Unless the customer had been using more than 2500 kWh per month. See Ex TEP-32 Jones RJ, Exhibit CAJ-RJ-1, Schedule H-3, page 6 of 23; TEP Reply Brief at 15.
[188] Tr. at 1657.
[189] TEP Reply Brief at 16.
[190] RUCO Opening Brief at 13. RUCO notes that its BSC and volumetric tier recommendations are independent of each other.
[191] *Id. citing* Ex SWEEP-1 Schlegel Dir at 8.

> run marginal costs. But fully-distributed costs analysts dare not avail themselves of this solution, since they are the prisoners of their own assumption that "the sum of the parts equals the whole." They are therefore under impelling pressure to fudge their cost apportionments by using the category of customer costs as a dumping ground for costs that they cannot plausibly impute to any of their other cost categories.[192]

RUCO argues that Dr. Overcast's claim that if Bonbright were alive today he would accept the Minimum System cost approach, should be rejected as a transparent attempt to support a methodology that has been rejected by nearly every state and leading regulatory academics, and is designed to increase the Company's basic service charge.[193]

RUCO supports the Basic Customer method of determining the BSC as it is consistent with Professor Bonbright's approach that customer-related costs of meters, billing and customer service should comprise the customer charge. RUCO argues that costs related to overall demand on the system such as distribution poles and wires are common to large groups of customers, not individuals, and thus should not be recovered on an individual basis.[194] RUCO argues that a customer who uses 500 kWh a month should not pay the same for utility poles as the same customer who uses 5,000 kWh per month, but under the Minimum System approach both customers would pay the same.[195] RUCO asserts the approach is unfair to the ratepayer and sends the wrong price signals to TEP's customers.[196]

RUCO states that the Company's proposed $15 BSC is approximately 16 percent of the total cost of service per residential customer of $93.61 per month, and is concerned that the Company will continue to advocate for the recovery of all fixed costs in the fixed charge.[197] Because, according to RUCO, the Minimum System approach does not have limits, it is the perfect methodology for the Company's alleged objective of including all fixed costs in a fixed charge. RUCO argues that the Commission should reject the Company's attempt to increase fixed charges through the Minimum System method, and claims that there are other ways to address fixed cost recovery that send appropriate price signals and are fair to ratepayers.

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[192] Bonbright, James C., Principles of Public Utility Rates, Second Edition. Arlington, Virginia, Public Utilities Reports, Inc. (1988). Print at page 492, Tr. t at 793-94.
[193] RUCO Opening Brief at 14.
[194] RUCO Opening Brief at 15.
[195] *Id.*; Ex TEP-30, Schedule CAJ-1, Schedule 1.
[196] Ex RUCO-10 Huber Dir at 19.
[197] RUCO Opening Brief at 15.

c. **EFCA**

EFCA asserts that the Company's use of the Minimum System method to calculate the customer charge is a significant deviation from the cost of service approach approved in its last rate case which relied on the Basic Customer approach. EFCA asserts that the Minimum System Method is a theoretical method based on the theoretical minimum system it would take to service the theoretical minimum customer, and leads to inaccurate and inflated customer charges.[198] Under this approach, a portion of distribution plant costs (lines, poles, transformers) are allocated to a customer class based on the number of customers but not on those customers' use of the system.[199]

EFCA argues that recovering a larger share of distribution system costs through customer charges, as occurs under the Minimum System method, is not fair based on historic use of the distribution grid. EFCA asserts that Bonbright, the father of modern rate design, has stated that including the costs of a minimum-sized distribution system among the customer-related costs is "indefensible."[200]

EFCA states that TEP proposed increasing the costs allocated to its customers from 6 percent in its last rate case to approximately 13 percent in this rate case, but has not justified or provided any reasonable rationale for adding these expenses to the basic service charge in this rate case.[201] EFCA states that although TEP's witness Overcast argues that increased diversity in load in the distribution system justifies the higher BSC, EFCA argues that there is nothing "individually customer related among these common distribution charges identified by Overcast", and he presents "no clear rationale or boundary for when and where certain facilities that are common to many users should be considered customer-related costs versus demand or energy-rated costs."[202] In addition, EFCA argues that Dr. Overcast fails "to demonstrate how the use of common distribution charges in the basic service follows the principle of cost-causation since the Minimum System Method does not only recover the incremental costs that arise from serving individual customers."[203] EFCA asserts that "averaging of

[198] EFCA Opening Brief at 25; Ex EFCA-10 Garret Dir at 36; see also RUCO Reply Brief at 11-12. EFCA's witness Garret calculated a $8.26 customer charge using the Basic Customer Method. Ex EFCA-10 Garret Dir at 10.
[199] Ex RUCO-10 Huber Dir at 10.
[200] Ex EFCA-9 Garret at 36.
[201] EFCA Opening Brief at 26.
[202] *Id.*; Ex RUCO-11 Huber Surr at 11.
[203] EFCA Opening Brief at 26.

customer charges also violates the 'matching principle' as there would undoubtedly be variations in the exact cost of the service drop and customer meter to serve individual customers."[204] EFCA states that the Basic Customer method limits the customer charge to a narrower, definable set of costs that can be tied to the customer with a greater degree of certainty and precision while safeguarding against inflated customer charges.[205] EFCA cites Utah, Illinois, Maryland, Texas, Arkansas, Colorado, and Washington as having rejected the Minimum System method.[206]

EFCA further argues that the Minimum System method reduces customer incentive to conserve energy because with a higher BSC, a customer will have control over a smaller portion of his bill.[207] Additionally, by recovering more of the Company's fixed costs through higher fixed rates, the resulting volumetric rate is lower, and a lower volumetric rate dampens the price signal customers receive to conserve. EFCA agrees that the higher fixed charge is regressive.[208]

EFCA argues that the evidence in this proceeding refutes the claim that the Basic Customer method "underestimates the unavoidable fixed system costs needed to serve a customer and that it "does not accurately reflect cost causation."[209] EFCA asserts that the reliability of the Basic Customer method is demonstrated by the minimal variances in the calculations by parties, other than the Company, to calculate the customer charge.[210]

d. **SWEEP/WRA/ACAA**[211]

SWEEP/WRA/ACAA state that because mandatory demand charges for residential customers do not appear to be a realistic possibility, the Company is attempting to load a portion of demand-related costs into the Basic Service charge by using the "completely contrived minimum system methodology" for determining the BSC.[212] SWEEP/WRA/ACAA state that as proposed by TEP, the BSC has room to grow to accommodate the addition of more demand costs, and they assert that

[204] *Id.*
[205] Ex EFCA-10 Garret Dir at 36.
[206] EFCA Opening Brief at 27.
[207] *Id.*
[208] EFCA Reply Brief at 17.
[209] *Id.* at 15.
[210] EFCA Reply Brief at 15-16.
[211] SWEEP, WRA and ACAA filed joint briefs.
[212] SWEEP/WRA/ACAA Opening Brief at 5.

although the Company disclaims the desire to move toward a straight fixed/variable rate, without demand charges, the Company's proposal heads in that direction.

SWEEP/WRA/ACAA state that under the Company's proposal, the BSC would include some amount of "minimum" poles, transformers and conductors, which otherwise would be allocated to the Residential Class as demand costs under the cost of service analysis. SWEEP/WRA/ACAA reject the Company's approach and favorably cite RUCO's witness Huber's characterization of the issue:

> [T]he major question, as I see it, in this phase of the case is what fence line you draw around the fixed charge. Historically the fence line has been defined by the basic customer method.
>
> Now the Company is recommending a significant change from how we have defined these costs for decades, so this is a call that the Commission is going to have to make at some point soon. Because moving up that fence line as the Company proposes, opens up every future rate case to a wide open field of possible fixed charges.
>
> ***
>
> And now we have a proposal to basically muddy the one area where we have some decent actual costs.[213]

SWEEP/WRA/ACAA argue that instead of increasing fixed charges, the Commission should focus on developing well-designed time-of-use rates.

Specifically, SWEEP and WRA oppose a higher BSC because:

(1) Higher fixed charges reduce customer control over utility bills as they cannot avoid the higher fixed charge or mitigate the rate increase (the majority of which is recovered in fixed charges).

(2) The fixed charge increase results in very high rate increases for lower usage and many low-income customers.

(3) Higher fixed charges and other TEP-proposed rate design changes will lead to higher electricity consumption.

(4) It is not necessary for fixed costs to be recovered through fixed charges, as for decades significant portions of fixed costs have been recovered through volumetric rates.

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[213] Tr. at 1463-4.

(5) Higher fixed charges are not needed to recover authorized costs, as TEP could recover authorized costs and reduce peak demand through properly designed TOU rates with a lower BSC without exposing customers to the problems caused by higher BSCs.[214]

SWEEP and WRA also argue that the higher BSC proposal violates a primary Bonbright criteria of ratemaking to discourage wasteful use of public utility services.[215]

SWEEP and WRA argue that the BSC should be determined using the Basic Customer method, and be set at no more than $10 for the residential class.[216] The SWEEP/WRA witness, Mr. Baatz, argues that the Minimum System method departs from long-standing Commission practice, is subjective, includes several categories of costs that are not customer related, and is not the common practice nationally. While Mr. Baatz calculated lower values for the BSCs for residential ($7.62) and GS ($11.97) customers using the Basic Customer method, SWEEP is willing to support the current BSC levels of $10 for residential customers and $15.50 for SGS customers.[217] SWEEP and WRA argue that the BSC is not intended to recover 100 percent of costs needed to serve a customer, but is intended to recover customer-specific costs (those that vary with the number of customers on the system). They argue that the Basic Customer method is the most equitable method proposed in this case, as including distribution costs in the service charge does not account for population density and would overcharge many customers, especially those in multi-family housing.[218]

ACAA requests that the fixed charge be held at $10 for low-income customers. ACAA states that it demonstrated that low-income customers are more likely to be low-use customers, and that it is indisputable that increases in fixed charges disproportionately impact low-use customers more than high-use customers because the fixed charge comprises a larger part of their bill. According to ACAA, the higher the fixed charge, the higher the bill before the customer even turns on a light and the less control they have over the bill total. ACAA contends that roughly 80 percent of low-income customers are not on Lifeline rates, thus, even if low-income assistance is available, it is not accessible by many low income customers.

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[214] SWEEP/WRA/ACAA opening Brief at 10.
[215] SWEEP/WRA-1 Baatz Dir at 5-20, SWEEP/WRA-2 WRA Baatz Surr at 3-14.
[216] SWEEP/WRA/ACAA Opening Brief at 11.
[217] *Id.* at 12.
[218] SWEEP/WRA/ACAA Reply Brief at 8.

e. **Vote Solar**

Vote Solar argues that the Commission should reject TEP's proposal to increase fixed charges because it would be a disincentive to energy efficiency and rooftop solar by reducing the volumetric per kWh rate, thereby giving customers less control over their bills. Vote Solar claims that increasing fixed charges is a regressive rate design that disproportionately harms low-use and low-income customers. Vote Solar asserts that increasing fixed charges is out-of-step with recent decisions in other states, which (based on a study of 37 cases in 2015) indicates that proposals to significantly increase the fixed charge were rejected.[219] According to Vote Solar, a BSC of $15 would be an uncommonly high fixed charge.

Vote Solar asserts that TEP's claim that even if the BSC is increased, the volumetric rates will also increase due to the revenue requirement increase, sidesteps the fact that the Company would recover a greater proportion of the revenue requirement increase through fixed charges rather than volumetric rates; and thus the volumetric rates are lower than they would be if the BSC remained unchanged.[220]

Vote Solar also argues that the Minimum System methodology improperly inflates customer-related costs by attributing variable distribution system costs to the customer charge, and that it has long been discredited. Using the Basic Customer method, Vote Solar calculated that the BSC should be $8.14 for residential customers and $17.51 for Small Commercial customers. Vote Solar recommends a $10 BSC for residential customers on standard two-part rates, and a $7 BSC for residential customers who elect the optional TOU and three-part rates. For small commercial customers, Vote Solar recommends a BSC of $17.50 for the standard two-part rates, and $14.50 for customers selecting the optional TOU or three-part rates.[221]

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[219] Ex RUCO-11 Huber Surr at 33. One 2015 study indicated the median fixed charge adopted in 37 cases in 2015 was $10.85 per month. In addition, Vote Solar sites a study from 2014-2015 that found 74 percent of utility proposals to increase fixed charges were rejected or scaled back and the average approved fixed charges in those cases was $11.87 per month. Vote Solar also cites testimony from Mr. Baatz for SWEEP that for the 161 largest utilities, the median customer charge was $9.50 per month.

[220] Vote Solar Reply Brief at 10.

[221] Vote Solar Opening Brief at 21.

f. Koch

Mr. Koch argues that the BSC should not increase by more than the overall rate increase, as these charges are not something that a customer can control, and do not contribute to decisions which promote conservation. He states that a lower BSC reduces the burden on those who can least afford the increase, and will increase adoption of more energy efficient products as the revenue requirement increase will be recovered in the volumetric charge. Thus, with the current residential BSC at $10.00, and the overall rate increase is about 7 percent, he recommends a BSC of not more than $10.70.[222]

g. Staff

In its Surrebuttal Testimony, Staff recommended reducing the Company's proposed customer charges for standard residential customers to $15.00 and $12.00 for non-standard residential customers based on the revised CCOSS.[223] Staff and the Company now agree on the BSCs for residential and small commercial customers.[224] Staff also agrees with the Company's use of the Minimum System method to determine the monthly service charge.[225]Staff believes that the inclusion of distribution costs in the calculation of the service charges is appropriate because these distribution assets must be available to service peak demand.[226]

In response to the parties who oppose the increase in the BSC, Staff states that the monthly service charge in the UNSE rate case was recently increased based on the Minimum System method that is under dispute in this case.[227] Staff states that its long-range goal is to move residential rates to a three-part rate and using the Minimum System advances Staff's goal.[228] Staff believes that reliance on studies that show other jurisdictions have rejected the Minimum System method are "suspect" because so much is unknown about the circumstances of the rejection—such has the costs to serve the average residential customers, what proportion of those costs are recovered through fixed charges, and whether

[222] Koch Opening Brief at 4.
[223] Ex S-12 Solganick Surr at 12. In Rejoinder testimony, the Company agreed to: (1) a $15 per month BSC for standard residential customers; (2) a reduced charge of $12 for the non-standard residential customer; (3) a $27 BSC for standard SGS customers and (4) a reduced rate of $22 per month for non-standard SGS customers.
[224] Staff Opening Brief at 15.
[225] *Id.*
[226] *Id.* at 16.
[227] Staff Reply Brief at 4.
[228] *Id.*; Tr. at 2367.

any of those utilities have declining sales volumes leading to under-collection of fixed costs.[229] Staff states the question to resolve isn't how many states use which method, but the balance of recovery of fixed costs and how to fashion rate design to allow TEP, in its unique circumstances, to recover costs it incurs when it cannot rely on the volumetric component to recoup a portion of the costs.

In response to arguments that not all fixed costs need to be collected through fixed charges, Staff argues that the Company's proposal will only collect a portion of its fixed costs. In addition, Staff believes that TEP offered persuasive testimony that the increase in BSC will not act as a disincentive to the adoption of EE, because as shown by a 2012 paper by Koichiro Ito of Stanford University, customers respond to the total bill rather than marginal energy prices.[230] Staff agrees with Dr. Overcast that residential customers do not have to understand the individual components of the rates to promote sound decisions related to a more complex rate design.[231]

Staff's recommended rates and revenue allocation to the Residential Class resulted in the average residential customer with a monthly usage of 785 kWh's in winter experiencing an increase of $8.73, or 10.1 percent, from $86.78 to $95.51, and average Residential customer with monthly usage of 1,150 kWhs in summer experiencing an increase of $8.74, or 6.6 percent, from $131.89 to $140.63.[232]

2. Reduction to two volumetric tiers

a. TEP

TEP proposes to eliminate two of the four volumetric tiers for its residential rates, which it claims will better align rate design with cost-causation.[233] TEP asserts that the current top two tiers result in a disproportionate recovery of fixed costs from high-use customers.[234] TEP argues the top two tiers are a significant driver of intra-class subsidization, have contributed to the Company's inability to earn its authorized revenue requirement, and do not send appropriate price signals to customers. The

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[229] Staff Reply Brief at 4.
[230] Staff Reply Brief at 5; Ex TEP-28 Overcast Reb at 93.
[231] Staff Reply Brief at 5. Staff notes that other witnesses agreed that customers respond to their total bills, citing EFCA witness Mr. Garret, Mr. Huber for RUCO, as well as TEP's witness Jones. Tr. at 2279; Ex RUCO-11 at 41; Ex TEP-32 at 16.
[232] Ex S-12 Solganick Surr at HS-8.
[233] TEP Opening Brief at 24.
[234] Ex TEP-30 Jones Dir at 41 and 45.

Company notes that eliminating the top two tiers only affects 0.5 percent of the bills issued, since 99.5 percent of the bills reflect usage of 3,500 kWhs or less.[235] TEP notes that under its standard residential rate proposal, the volumetric rate in the second tier is almost identical to the rate in the current third tier, so that all customers will have the same incentive to conserve.[236]

TEP claims that RUCO is mistaken when it asserts that 41 percent of higher usage customers will see a rate decrease in the summer if the number of tiers is reduced, first because the analysis fails to include the fuel rates, and second because it ignores that the proposed volumetric rates will be higher for the first and second tier. TEP states that when these elements are factored in, the number is actually 0 percent.[237]

Finally, TEP argues the record shows that multiple tiers are not helpful to customers, and that the Company receives many complaints when customers hit the higher tiers about paying more when they use more, especially in the summer.[238]

b. <u>RUCO</u>

RUCO supports eliminating the current fourth tier in the standard residential rates, but opposes TEP's proposal for only two tiers. The top tier currently applies to usage greater than 3,500 kwh/month. RUCO's analysis indicates that only about 1 percent of the bills and revenues are currently associated with the top tier, and thus its elimination will have little impact.[239] In contrast, RUCO states, a significant number of customer bills and revenues collected are from the third tier, and thus, its elimination will have significant impacts on a large number of customers. RUCO is concerned about how eliminating the third tier will impact low-use customers, because it would mean a greater share of the utility's costs will necessarily be recovered through the first and second tiers, and the low-use customers, who RUCO states also tend to have less income and less discretion over their energy consumption, will likely experience bill and rate increases.[240] RUCO asserts that the Commission should avoid the regressive policy of concentrating bill increases on lower usage customers.

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[235] TEP Opening Brief at 25.
[236] TEP Reply Brief at 17.
[237] TEP Reply Brief at 18. Ex TEP-31 Jones Reb at 37-38.
[238] Ex TEP-31 Jones Reb at 35-36.
[239] RUCO Opening Brief at 18; Ex RUCO-10 at 23-24.
[240] RUCO Opening Brief at 19.

In addition, RUCO asserts that eliminating the third tier will mean higher usage customers will experience a decrease in the marginal price per kWh consumed, which reduces the price signal to save energy from the group of customers with the highest consumption. RUCO estimates that approximately 41 percent of customers who are higher-end users will experience a rate decrease in the summer under the Company's proposal.[241] RUCO states that these high-use customers are likely to have the greatest discretion over their energy usage.

c. Vote Solar

Vote Solar argues that eliminating the upper two tiers for high usage customers is a regressive rate design that would disproportionately harm low-usage and low-income customers, and would also create a disincentive for rooftop solar and energy efficiency.[242] Vote Solar states that when the Commission approved an inclining block rate structure in 2008, it wanted to "promote energy conservation and beneficial load shifting."[243] Vote Solar claims the Commission had full knowledge that the high usage tiers would shift costs from low-usage customers to high-usage customer. Vote Solar argues that TEP presents no compelling reason to abandon the current inclining block rate structure.

In response to TEP's claim that volumetric rates are increasing under its proposal, Vote Solar notes that it will be the average and low-usage customers who pay the higher rates, and that the customers with the highest consumption will pay reduced volumetric rates. Vote Solar is concerned that the highest use customers, with the greatest discretion over energy use, will receive a disincentive to conserve.[244]

d. ACAA

ACAA opposes eliminating the third residential volumetric rate tier because having only two tiers would push even more cost recovery onto lower-use customers.[245] ACAA states that according to EIA, 49 percent of all Arizona residents use less than 1,000 kWhs per month, while 65 percent of low income customers use less than 1,000 kWh per month. Thus, ACAA asserts that decreasing the number

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[241] Ex RUCO-10 Huber Dir at 26.
[242] Vote Solar Opening Brief at 21.
[243] Decision No. 70628 (December 1, 2008) at 46.
[244] Vote Solar Reply Brief at 12.
[245] SWEEP/WRA/ACAA Reply Brief at 13.

of tiers makes low-use bills less affordable and creates a disproportionate burden for low-income customers.[246]

e. Koch

Mr. Koch argues that a higher marginal rate for electricity for higher usage encourages more efficient choices. He asserts that it is important to maintain three tiers, in order to drive efficient decisions and reduce the burden on those who cannot afford a higher cost of electricity. He argues that by reducing the cost of the first 500 kWhs, and increasing the cost of electricity above 1,000 kWhs per month, basic needs remain more affordable.[247]

Mr. Koch states that "the most distressing aspect of this rate case is the disproportionate increase in rates to those who use the least amount of energy."[248] He urges the adoption of rates that minimize the negative effect of the rate increase on those who can least afford it. He argues that by maintaining three tiers of volumetric rates and a low BSC the new rates can be fairly applied without tipping the scales to burden the most vulnerable in our society.[249]

f. Staff

Staff supports eliminating the third and fourth tiers and that "the remaining inclination should be flattened as the residential customer's load factor increases as usage increases, which does not support inclined rates."[250] Staff states that by eliminating the third and fourth tiers, and with the small increase in the monthly service charge, the impact within the LFCR will be lessened.

3. Time-of Use ("TOU") Rates

a. TEP

TEP is proposing a two-part TOU rate structure similar to that recently approved for UNSE, as well as an optional three-part TOU rate. The Company will default new customers to the TOU two-part rate, unless they express a desire to be placed on one of the other rates. TEP proposes a BSC of $12 (compared to the current BSC for TOU of $11.50) and two volumetric tiers. The peak period in summer will be 3:00 p.m. to 7:00 p.m. (shortened from the current 2:00 to 8:00 p.m.), and the winter

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246 *Id.*
247 Koch Opening Brief at 3.
248 *Id.* at 4.
249 *Id.*
250 Staff Opening Brief at 16; Ex S-10 Solganick Dir at 29.

peaks will be shortened to 6:00 to 9:00 a.m. and p.m. (from 6:00 to 10:00 a.m. and 5:00 to 9:00 p.m.). TEP believes that its TOU rate, in combination with customer outreach and education, is a gradual (with fewer unintended consequences) and appropriate step to encourage more customers to use TOU rates.[251]

TEP's proposed Residential TOU rates follow:

Residential Time of Use (TE-R80)[252]

	Current Rates	Proposed Rates	$ Increase	% Increase
Basic Service Charge	$11.50	$12.00	$.50	4%
Sum On-Peak First 500 kWh	$0.066800	$0.063804	-.0.002996	-4%
Sum On-Peak 501-1,000 kWh	$0.066800	$0.079600	0.012800	19%
Sum On-Peak 1,001-3,500 kWh	$0.066800	$0.079600	0.012800	19%
Sum On-Peak > 3,500 kWh	$0.066800	$0.079600	0.012800	19%
Sum First Off-Peak 500 kWh	$0.051800	$0.063804	0.012004	23%
Sum Off-Peak 501-1,000 kWh	$0.051800	$0.079600	0.027800	54%
Sum Off-Peak 1,001-3,500 kWh	$0.051800	$0.079600	0.027800	54%
Sum Off-Peak > 3,500 kWh	$0.051800	$0.079600	0.027800	54%
Win On-Peak First 500 kWh	$0.056800	$0.063804	0.007004	12%
Win On-Peak 501-1,000 kWh	$0.056800	$0.079600	0.022800	40%
Win On-Peak 1,001-3,500 kWh	$0.056800	$0.079600	0.022800	40%
Win On-Peak > 3,500 kWh	$0.056800	$0.079600	0.022800	40%
Win First Off-Peak 500 kWh	$0.041800	$0.063804	0.022004	53%
Win Off-Peak 501-1,000 kWh	$0.041800	$0.079600	0.037800	90%
Win Off-Peak 1,001-3,500 kWh	$0.041800	$0.079600	0.037800	90%
Win Off-Peak > 3,500 kWh	$0.041800	$0.079600	0.037800	90%
Base Power Summer On-Peak kWh	$0.050669	$0.066568	0.015899	31%

[251] With the shorter on-peak periods being proposed, the Company has proposed to cancel the current Super-Peak TOU rate.

[252] Ex TEP-32 Jones RJ at CAJ-RJ-1 at 17. TEP proposes On-Peak Hours from 3:00 pm to 7:00 pm in summer, shortened from the current on-peak hours of 2:00 pm to 8:00pm; and winter on-peak of 6:00 am - 9:00 am and 5:00 pm – 9:00 pm.

Base Power Summer Off-Peak kWh	$0.026679	$0.026332	-0.000347	-1%
Base Power Winter On-Peak kWh	$0.032893	$0.032568	-0.000325	-1%
Base Power Winter Off-Peak kWh	$0.027092	$0.025655	-0.001437	-5%
PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Residential Demand Time of Use (TE-RXXX)

	Current Rates	Proposed Rates
Basic Service Charge	N/M	$12.00
Demand 0-7 kW	N/M	$8.75
Demand >7 kW	N/M	$12.50
Sum On-peak kWh	N/M	$0.031740
Sum Off-Peak kWh	N/M	$0.031740
Win On-Peak kWh	N/M	$0.031740
Win Off-Peak kWh	N/M	$0.031740
Base Power Summer On-Peak kWh	N/M	$0.066568
Base Power Summer Off-Peak kWh	N/M	$0.026332
Base Power Winter On-Peak kWh	N/M	$0.032568
Base Power Winter Off-Peak kWh	N/M	$0.025655
PPFAC Charge kWh	N/M	$0.000000

TEP states that other parties are seeking radical changes to the current TOU rate, such as 3-4x spreads between on-peak and off-peak rates, and off-peak rates of $0.01/kWh, which are far below marginal cost and would send a poor price signal. TEP states it is concerned that such radical changes would result in increased intra-class subsidies or other unintended consequences.[253]

b. SWEEP/WRA/ACAA

SWEEP/WRA/ACAA argue that a properly designed TOU rate is an obvious alternative to fixed charges (including demand charges) and notes that even Company witnesses have acknowledged that well-designed TOU rates do a superior job of recovering fixed costs than the existing two part rate

[253] TEP Reply Brief at 18.

structure and have been shown to reduce peak demand.[254]

SWEEP/WRA/ACAA note that only TEP and RUCO proposed TOU rates in this proceeding. SWEEP/WRA/ACAA state that the Company proposed an on-peak rate based on short-term marginal costs, with the result that the differential between on-peak and off-peak is not very significant. SWEEP/WRA/ACAA believe this structure will make it difficult to attract customers to the Company's proposed TOU rates.[255] They state that RUCO has taken a longer term perspective by looking at the next marginal unit of generation from TEP's IRP and arriving at a higher on-peak rate. SWEEP/WRA/ACAA believe the RUCO approach would have the effect of reducing peak demand, plus the differential between on and off-peak with RUCO's proposed rate, combined with lower BSC, will provide a greater incentive for customers to migrate to TOU rates.[256]

SWEEP and WRA argue that effective, customer-friendly TOU rates give customers more control over their energy bills, have less harmful impacts on lower usage customers, help reduce wasteful energy use and peak demand by sending strong price signals, and give TEP a reasonable opportunity to recover authorized costs. Thus, they claim, properly designed TOU rates align the interests of the Company and its customers.[257] In order to achieve significant reductions in peak demand, a large number of customers must opt for TOU rates, thus, SWEEP and WRA recommend customer-friendly TOU rates as follows:[258]

1. A lower BSC to give customers greater control;
2. A shorter on-peak window (3 hours in both summer and winter) to make it easier for customers to shift load to the lower-priced off-peak period;
3. A meaningful spread or differential (3-4x) between on- and off-peak prices to give an incentive to reduce consumption and shift load and allow for bill savings from shifting load and reducing energy use;
4. Retained tiered rates in order to discourage wasteful energy use by providing an additional

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[254] SWEEP/WRA/ACAA Opening Brief at 7-8 and 12-14; Tr. at 351.
[255] SWEEP/WRA/ACAA Opening Brief at 8; Tr. at 1486; *see also* SWEEP/WRA/ACAA Reply Brief at 10-11.
[256] SWEEP/WRA/ACAA opening Brief at 8. SWEEP/WRA/ACAA recommend adopting RUCO's proposed TOU rates (although with a shorter on-peak period), with a $10 BSC, and to give the rates an opportunity to work and provide data for use in a future rate case.
[257] SWEEP/WRA/ACAA Opening Brief at 13.
[258] SWEEP/WRA/ACAA Opening Brief at 13-14.

incentive to save energy.

Mr. Schlegel, a witness for SWEEP, recommends that the BSC remain at $10 for standard, non-TOU customers (which SWEEP claims is consistent with employing the basic customer method and supported by the record), and that the BSC be lowered to $7 as a positive incentive to encourage customers to enroll in TOU rates.[259] SWEEP argues that it is not appropriate or in the public interest to artificially increase the BSC to a level higher than $10, even for customers who choose not to enroll in TOU rates.

c. **RUCO**

RUCO did not address TOU rates specifically in its post-hearing briefs, but in its Surrebuttal Testimony proposed the following TOU rates:[260]

Full-Requirements TOU

Basic Service Charge	$10.00		
Delivery	Summer	Winter	
On-Peak	$0.178	$0.12	
Off-Peak	$0.058	$0.051	
Fuel	Low User	Medium User	High User
Floor kWh	0	500.01	1000.01
Ceiling kWh	500	1000	
Rate	$0.011	$0.0241	$0.0421
	Summer	Winter	
Start Month	May	October	
End Month	September	April	
Peak Hours	Summer	Winter	
Peak Start	3:00 PM	6:00 AM & PM	
Peak End	7:00 PM	9:00 AM & PM	

Optional Three-part TOU Rate

Basic Service Charge	$10.00		
Demand Charges	Summer	Winter	kW Break Point
Below Break Point	$4	$2	4.50 kW
Above Break Point	$12	$4	
Delivery	Summer	Winter	
On-Peak	$0.1690	$0.0950	
Off-Peak	$0.0358	$0.0295	

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[259] SWEEP/WRA/ACAA Opening Brief at 14.
[260] Ex RUCO-11 Huber Surr at 6-7.

Fuel	Low User	Medium User	High User
Floor kWh	0	500.01	1000.01
Ceiling kWh	500	1000	
Rate	$0.011	$0.0241	$0.0421

	Summer	Winter
Start Month	May	October
End Month	September	April

Peak Hours	Summer	Winter
Peak Start	3:00 PM	6:00 AM & PM
Peak End	7:00 PM	9:00 AM & PM

d. Staff

Staff supports a move to three-part TOU rates for residential customers over the long term, and in this case is recommending an optional three-part TOU rate be made available to Residential and SGS customers.[261] Staff recommends that all Residential and SGS customer bills include the customer's monthly On-Peak and Off-Peak demands (although the demand values would not be used for billing unless the customer has chosen the optional demand rates). Staff also recommends that the Company develop a customer information portal that would provide customers with the ability to review their demand and energy consumption and evaluate various optional rates so that customers can make informed decisions about rates, energy efficiency and emerging technologies.

4. Analysis and Resolution of Residential and SGS Rate Design

In this phase of the proceeding there is no dispute about the rate options that TEP has proposed for the Residential and SGS Classes. The dispute is over how much of the approved rate increase should be apportioned among the BSC and the energy charges, how many volumetric tiers are appropriate for the Residential Class and how to design the rate differentials for the TOU proposals.

This case includes a substantial rate increase for the residential class. We would like to provide ratepayers with as much opportunity as possible to manage their total bill as we can while also providing rates that give the Company a reasonable opportunity to collect its authorized revenue. This means being moderate in any increase to the fixed charge. We note that while Staff has expressed a long-term goal of moving toward three-part rates for residential customers, the Commission has not endorsed Staff's position, although we have recognized that two-part rates contain certain limitations

[261] Staff Opening Brief at 38.

and inequities as the Residential Class becomes more diverse in its usage patterns. As we stated in the UNSE rate case, we would like to encourage the greater use of TOU rates to see if they can ameliorate some of the short-comings of the standard two-part rate.

After considering the totality of evidence in this proceeding, we adopt RUCO's recommendation for a BSC of $13 for Residential standard offer customers and $10 for residential TOU rates in order to provide an incentive for TOU adoption. The 50 percent increase in the BSC as proposed by TEP and Staff is too high given all the other forces working in this case. We are aware that a $13 standard offer BSC exceeds the maximum charge calculated by most parties using the Basic Customer Method. By approving this charge we are not rejecting the Basic Customer Method, or adopting the Minimum System Method, but we use both methods to inform our policy decision.[262] Those customers who wish to achieve greater control over their bills are free to try the TOU options with a $10 monthly charge. We find that this decision appropriately balances the interests of the rate payers to manage their bills with the Company's need for stable revenue recovery.

We find that four volumetric tiers for the Residential Class is excessive. In this case, we approve three tiers for both the standard two-part and TOU rate offerings. Again, the significant rate increase that will impact ratepayers warrants providing mitigating measures to protect lower-income, lower-use customers who have less ability to make significant reductions in energy use.

To the extent there are inequities as a result of the current rate design caused by DG customers, we will address any such claims in Phase 2 of this proceeding.

As stated above, the BSC for residential TOU should be $10 per month. We find that TEP's proposed structure for its TOU rates is reasonable. RUCO's proposed off-peak rates are problematic because the first tier, and maybe the second tier, are below the marginal cost of fuel.[263] Because TOU rates are supposed to send price signals when the cost of fuel or power is high, the rates should reflect the costs of fuel and the differential should generally reflect the differentials in fuel costs. The correlation does not need to be exact, however, as the goal is to find a balance between allowing the

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[262] Throughout this proceeding we have appreciated the testimony of Mr. Koch, who although not a professional rate analyst, has extensive experience dealing with electric rate payers and analyzing the effects of utility rates on consumers. He recommended that any increase in the BSC be limited to the overall percentage increase. While the approved BSC exceeds Mr. Koch's recommendation, we have relied on his recommendation as a moderating force.

[263] Tr. at 1659-1662.

Company to recover its revenue and giving the consumer the signal to use less at peak times and shave the peak. In times when fuel and power costs are relatively low, the signal to shift load is dampened if the differential in on- and off-peak rates is not sufficient. This is where the art, rather than science of ratemaking enters the picture. While we find TEP's proposed TOU rate design appropriate, its proposed rates were based on its revenue allocation to the Residential Class and its proposed BSC. As TEP revises its TOU rates to reflect our higher allocation to Residential Class and the lower BSC, the Company should keep the goals of TOU rates in mind.

TEP proposed a \$27 per month BSC for the single phase SGS customers, an increase of \$11.50, or 74 percent, from the current rate of \$15.50. For three-phase SGS customers, TEP proposed to increase the BSC from \$20.50 to \$32.00, an increase of \$11.50, or 56 percent. We note that under current rates, the BSC comprises approximately 9.6 percent of the total bill for the average SGS customer using 1,340 kWhs in winter and 5.8 percent of the total bill for the average SGS customer using 1,846 kWhs per month in summer.[264] Under TEP's proposed rates, the \$27 BSC would comprise 15.2 percent of the total bill in winter and 9.7 percent in summer for the average customers.

For the same reasons discussed in connection to the Residential Class, a lower BSC results in higher energy charges in order to collect the same amount of revenue from the class. Higher energy charges better incentivize energy efficiency and give more control to the total bill to customers. We find that a more moderate increase in the single phase SGS rate would reasonably balance the interests of ratepayers and the Company. We find that a \$25 BSC for the single phase SGS rates, a 61 percent increase over the current rate, strikes the reasonable balance of competing interests. We find that TEP's proposed increase in the BSC for the three-phase service is reasonable.

Staff recommended that all Residential and SGS customer bills include the customer's monthly On-Peak and Off-Peak demands (although the demand values would not be used for billing unless the customer has chosen the optional demand rates) and that the Company develop a customer information portal that would provide customers with the ability to review their demand and energy consumption and evaluate various optional rates so that customers can make informed decisions about rates, energy

[264] Ex TEP-32 Jones RJ CAJ-RJ-1 at pp 57-58.

efficiency and emerging technologies. We do not require TEP to provide demand information on customer bills for those who have not opted for the three-part rates, however, we believe that Staff's suggestion that TEP provide a way for customers to easily compare the impacts of various rate designs provides a good way to educate customers about more complex, or new rate design concepts. We understand that Staff has a long-term goal of implementing demand charges for all ratepayers. We do not opine on the merits of this goal, however, we believe that providing rate payers access to the tools and information suggested by Staff in advance of proposing more wide-spread application of demand charges will allay fears and be an important part of any customer education plan. Thus, we direct TEP to develop a customer information portal as suggested by Staff. We do not have information regarding how easily such a tool can be developed, but believe that within 90 days of the effective date of this Decision, TEP should be able to submit a comprehensive customer education plan that includes these tools. Customer education is likely to be an important part of Phase 2 of the proceeding, and having a proposed plan to discuss in that proceeding could streamline the post-Phase 2 process.

A. Lifeline Rates

1. TEP

TEP currently has 27 different Lifeline rates, 22 of which are frozen and many of which have only a handful of customers. The multiple Lifeline rates have a variety of discount mechanisms, ranging from flat dollar discounts to varying percentage discounts. TEP contends that the multiple options are confusing for both customers and the Company's customer service representatives. TEP seeks to simplify its Lifeline rates by moving all Lifeline customers to a standard residential rate and then provide a flat monthly discount. TEP explains that the flat discount is designed to produce a discount similar to what the Lifeline customer currently receives. Given the current complexity of the Lifeline rates, the Company is proposing four different levels of monthly discount: \$15, \$18, \$30 and \$40.[265] TEP states that its Lifeline proposal increases the total annual Lifeline funding from \$1.8 million to \$2.8 million. TEP is also committing to a \$150,000 annual shareholder contribution for the next five years to fund low-income bill assistance programs.

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[265] TEP Opening Brief at 27; Ex TEP-32 Jones RJ Ex CAJ-RJ-2.

TEP believes that its increased discounts are reasonable. It states that although some concern was raised that a "handful" of Lifeline customers on a few of the frozen Lifeline rates may see a larger percentage increase, TEP states no concrete proposals beyond TEP's proposal have been provided.[266] In response to Staff's concerns, the Company indicates that it may be amenable to increasing a limited number of discounts, but is concerned about increasing the costs on other residential customers.[267]

ACAA has requested that the Company automatically enroll customers in Lifeline and should recover the costs of enrolling additional Lifeline customers through one of its adjustor mechanisms.[268]ACAA requests an implementation plan, with input from interested stakeholders, be prepared within 90 days of rates going into effect. TEP responds that neither of these concepts were set forth in testimony and are not sufficiently defined to be approved now. TEP states it intends to follow the Commission's guidance in the recent UNSE rate case Order and will investigate how to implement automatic enrollment.[269] With respect to ACAA's request to develop a sliding scale for Lifeline discounts, TEP states that it intends to assess the feasibility of such an approach and may propose such a program in its next rate case.[270]

TEP takes issue with ACAA's statement in its Opening Brief that all major utilities in Arizona, including UNSE, UNS Gas, and TEP have agreed to no longer accept payments through payday lenders.[271] TEP clarifies that in 2007 it agreed not to actively promote payday lending businesses as payment centers and to identify other payment locations. For example, Wal-Mart stores are available to accept payments. TEP removed the link to ACE Cash Express ("ACE") from its website in response to Ms. Zwick's request, and the service agreement with ACE, executed in 2000, was not renewed in 2007.[272] TEP states that it continues to honor its commitment to not actively promote ACE, however, "non-authorized" payment locations, such as ACE, are abundant and offer bill pay as a service to their own customers who choose to do business with them.

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266 TEP states that under its proposal, those customers will receive a discount of $40 per month (almost $500/year). TEP Reply Brief at 18; Ex TEP=31 Jones Reb at 22; Ex TEP-32 Jones RJ, Ex CAJ-RJ-2.

268 ACAA Opening Brief at 26-27.
269 TEP Reply Brief at 32.
270 *Id.* at 19.
271 ACAA Opening Brief at 28-29.
272 TEP Reply Brief at 33.

TEP calculated the following bill impacts for customers on the Standard Lifeline rates (based on its revenue allocation to the Residential Class): in the winter, a standard Lifeline customer using 785 kWh per month[273] would experience an increase of $2.41, or 3.1 percent, from $77.78 to $80.19, after the discount is applied. Small users with usage of 473 kWh would experience a bill decrease of $0.12, or 0.3 percent, from $45.72 to $45.60, after the proposed discount.[274] In summer, a standard Lifeline customer using 1,150 kWh's per month[275] would see a bill increase of $1.79, or 1.5 percent, from $122.89 to $124.68, after the discount, and in winter, a standard Lifeline customer using 684 kWhs would see an increase of $0.81, or 1.2 percent, from $70.04 to $70.85, after a discount of 11.4 percent.[276]

2. ACAA

A large majority of households that are eligible for Lifeline rates are not currently enrolled, which ACAA asserts leads to an increased home energy affordability gap. ACAA acknowledges that TEP has engaged in outreach, but notes that the Company has not implemented an automatic enrollment for people who receive energy assistance. ACAA states that SRP has increased enrollment 3-5 percent using such a program. ACAA requests an implementation plan, with input from interested stakeholders, be prepared within 90 days of the implementation of the rates in this case. ACAA states that it would be appropriate for the Company to recover the costs of enrolling additional Lifeline customers through one of its adjustor mechanisms.[277]

ACAA proposed "to hold Lifeline customers harmless." ACAA believes that moving currently frozen Lifeline customers to the proposed rates would result in a significant rate shock for the affected customers. ACAA states with the proposed increase, eight of the frozen rates will see an increase above 20 percent, six would be above 30 percent, and three would be above 40 percent.[278] ACAA argues that the Company should keep the frozen rates frozen until attrition eliminates the rate.[279]

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[273] The Residential Class average.

[274] Ex TEP-32 Jones RJ at H-4 at 19. Lifeline customers using 740 kWh would see a bill increase of $2.00, or 2.7 percent; Lifeline customers using 1,071 kWh would see a bill impact of $3.95, or 3.6 percent; and those using 1,310 kWh would see a bill impact of $2.95, or 2.2 percent.

[275] The Residential Class average.

[276] Ex TEP-32 Jones RJCAJ-RJ-1 at 6.

[277] SWEEP/WRA/ACAA Opening Brief at 26-27.

[278] *Id.* at 35.

[279] *Id.* at 36.

According to ACAA, households in deep poverty spend 17.5 percent of their income on energy, while those from 51-100 percent of the Federal Poverty Guidelines ("FPG") have an energy burden of 9.3 percent, and the energy burden for households from 100-150 percent FPG is 5.7 percent.[280] ACAA argues that providing more households with affordable electricity benefits the utility as well as the customers, as charging a lower total bill for low-income customers has been shown to increase bill coverage (the percentage of the bill paid by the customers). ACAA states that with the increase in revenue, higher bill coverage results in lower costs to collect, fewer disconnects and reconnections, lower carrying costs and other non-energy benefits.[281]

ACAA believes that TEP's four levels of discounts to be applied to the frozen Lifeline Rates should be expanded to all Lifeline customers through the tiered rate discount ACAA has proposed.[282] Under this proposal, customers at less than 50 percent of the FPG would receive a $40/month discount, the customers from 51-100 percent of the FPG would receive $30/month discount, and households from 101-150 percent of the FPG would receive a $15/month discount. ACAA states "[t]he discounts are already in the system; all the Company would need to do is determine where the low-income household falls on the federal poverty guideline by asking for income and number of people in the household."[283] ACAA supports increasing the discounts for the "several hundred customers" who TEP identified as receiving significant rate shocks.

Furthermore, ACAA asserts that there is too much need in the community for TEP to merely "look into" ways to increase Lifeline enrollments, and ACAA would oppose a diversion of Lifeline funds to study ways of providing direct solar support for low-income customers.[284]

3. <u>Staff</u>

Staff describes the Company's Lifeline proposal in its Closing Briefs, but does not take a position.[285] During the hearing, Staff supported TEP's proposed flat Lifeline discount, but expressed a concern that there could be a number of customers (estimated between 80 and 350) who may require

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[280] *Id.* at 34.

[281] *Id.* at 34; ACAA states the benefits have been observed in Indiana, Colorado, New Jersey and other states. *See*, http://www.synapse-energy.com/sites/default/files/Low-Income-Assistance-Strategy-Reveiw-14-111.pdf.

[282] SWEEP/WRA/ACAA Reply Brief at 14.

[283] *Id.*

[284] *Id.* at 15.

[285] Staff Opening Brief at 30.

higher discounts in order to be in parity with their current discounts.[286] Mr. Solganick recommended:

1. The validation of the Lifeline impact and the required discounts be performed after the revenue allocation and residential rate design is determined.

2. The Company should "prove out" that the level of Lifeline discounts after the finalized charges in rates is at or above the test year value.

3. The Company should address those Lifeline customers who will see a significant increase in their bill as a result of adopting the fixed discount. Because some customers have such a deep discount that even a $40 monthly Lifeline credit may not keep them from seeing significant increases, and in such cases, the Company should confirm that the rate is frozen, that the customer is eligible for this large discount and that there is not another Lifeline rate that would be more advantageous. Staff suggests that the Company provide suggestions to minimize the impact either by providing a larger discount or by holding those customers in their frozen rate structure.[287]

Thus, Mr. Solganick suggested looking at the rate impacts on each individual customer on the frozen Lifeline rates and using the average residential increase as a guide for determining an acceptable increase for a Lifeline customer. He also believes that a dollar limit on the impact is an important factor. In discussing the appropriate impact on Lifeline customers Mr. Solganick testified:

> If I were doing it, I would suggest both a percentage number that has relationship to the average customers and then also a dollar floor, again, getting back to the idea if the percentage is high but the impact is dollar-wise very small, who cares.[288]

Staff's calculation of the bill impact on typical Lifeline customers shows that in winter, a standard Lifeline customer using 785 kWhs would experience an increase of $2.73, or 3.5 percent, from $77.78 to $80.51, after the applicable discounts. In summer, a standard Lifeline customer using 1,150 kWh's would see a monthly increase of $4.92, or 4.7 percent, from $104.71 to $109.63, after applying the discounts.[289]

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[286] Ex S-11 Solganick Surr at 18; Tr. at 2342.
[287] Ex S-11 Solganick Surr at 19.
[288] Tr. at 2360-61.
[289] Ex S-11 Solganick Surr at HS-8.

4. Analysis and Resolution of Lifeline Rates

ACAA provided evidence that supports the need for Lifeline rates. As TEP's rates increase, the amount of support for Lifeline customers must also increase in order to moderate the impact of the rate increase. In this case, TEP proposes to increase the Lifeline support budget from $1.8 million to $2.8 million, a 55 percent increase. The increase is based on the test year billing determinants of Lifeline customers. The Company's proposed Lifeline budget was based on its proposed allocation to the residential Class and rates, and will need to be adjusted to reflect the allocation we approve herein.

ACAA does not seem to oppose the discount approach to Lifeline rates, but is concerned that the discounts may not be sufficient to protect the Lifeline participants from excessive increases. We find that the proposed flat rate discount is reasonable, however for some of the Lifeline customers on the frozen Lifeline rates, even a $40 a month discount may result in an unreasonable bill impact. Some of the frozen rate schedules have only one or two customers, and others have several thousand customers.[290] We cannot at this time determine the bill impacts for the individual customers on the frozen Lifeline schedules. However, Staff has identified between 88 and 350 Lifeline customers on the frozen rates who may be disproportionately affected by the proposal. We adopt Staff's suggestion that once TEP has designed the rates in response to our directives, TEP should confirm for these customers that they are eligible for the discount and that there is not another Lifeline rate that would be more advantageous. The revenue increase for the Residential Class is approximately 12 percent, with the average standard offer residential customer expected to experience a bill increase of approximately 10 percent in winter and 6.6 percent in summer. For the frozen Lifeline customers, the Company should use the impacts on the Residential Class as a guide and propose Lifeline rates that minimize the impacts on these vulnerable customers either by providing a larger discount or by keeping those customers in their frozen rates. If under the proposed discount approach the impact on those few customers on the frozen Lifeline rates cannot be held to a reasonable amount, it may be most cost-effective to just keep these few customers on their current frozen rates rather than administer individual discounts. The cost of providing extra discounts to the frozen Lifeline customers should not be substantial, but may not be

[290] *See* Ex TEP-32 Jones RJ at CAJ-RJ-2.

known until each customer's bill is analyzed.

It is not possible for us to determine if the resultant impacts on these 88-350 frozen Lifeline customers identified by Staff is reasonable until the analysis is performed. We believe that as a general proposition, if the impact on these frozen Lifeline customers would be greater than 12 percent of their average annual monthly bill, the proposal may be burdensome.

We do not have sufficient information to determine if ACAA's proposal to have tiered discounts would significantly impact the overall cost of the Lifeline program, or how it might affect current Lifeline customers, as we do not know the current mix of lifeline enrollees. It is an idea worth exploring, and TEP has expressed a willingness to study the proposal for its next rate case. Thus, we direct TEP to provide testimony in its next rate case on whether the tiered discount proposal would be an improvement over the current Lifeline program.

Any increase in enrollment until the next rate case will increase the amount of discounts provided without an increase in the amounts recovered from other rate payers. This is not a good reason, however, to discontinue outreach or not to explore ways to enroll eligible consumers. If low-income ratepayers are better able to manage their utility costs, in theory the costs of serving these customers should decline. Waiting until the next rate case for a proposal to enact automatic enrollment is unnecessary delay. We direct TEP to investigate instituting an automatic enrollment program, and if it is unable to implement the program by December 31, 2017, to file a report with the Commission explaining why an automatic or streamlined process could not be implemented, or would not be cost effective or beneficial.

B. <u>Rate Design for Medium, Large, and Industrial Customers</u>

1. <u>TEP</u>

a. <u>MGS Rates</u>

TEP says that a critical part of modernizing its rate design is to create a new Medium General Service ("MGS") rate. Currently, TEP has two general service classes, SGS and LGS, each of which contain a wide range of customer load sizes. Current usage under the SGS rates ranges from less than a few hundred kWh per month to one customer who uses one million kWh per month.[291] TEP states that rate design is based on average usage for the class, which means that the high usage customers, which also tend to be high load factor customers who use the grid more efficiently, are not "rewarded" in rates for their efficiency.[292] TEP claims that the current SGS class is simply too broad to appropriately match cost causation to cost recovery.[293]

TEP's proposed MGS class would apply to customers with a load of 20 kW to 300 kW, and could contain approximately 4,000 former SGS and 85 former LGS customers. Before a customer is transferred from SGS to MGS, the customer must use 24,000 kWh in total over two consecutive months. TEP believes that the higher load customers will likely benefit from moving to the MGS rates, and that many transferred SGS customers will see bill reductions.[294]

The new MGS rates will be similar to the current LGS rates with a 75 percent ratchet, winter/summer differential, and a single energy rate tier. The Company is proposing a $40 BSC for the MGS class. Any customer that exceeds the 300 kW cap for a second billing month in a 12-month rolling period will automatically be moved, in the subsequent month to the LGS Class.[295] Because the MGS class includes a three-part rate with a demand component and ratchet, and most of the customers that will be moved to this rate will have previously been on a two-part rate and have no experience with demand charges, the Company proposes several steps to mitigate the impact of the move, including: (1) multiple forms of communicating with the affected customers and developing a plan to inform the customers before they will be moved; (2) a transition period that will allow 12 months for the customer to adapt to a demand charge before it is actually reflected on the bill;[296] and (3) a seasonality clause that would protect extremely counter-seasonal customers.[297]

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[291] Ex TEP-2 at Schedule H-5, page 29-45.
[292] TEP Opening Brief at 31.
[293] TEP Opening Brief at 31.
[294] TEP Reply Brief at 20; Ex TEP-43 (Table re SGS to MGS bill impacts).
[295] Ex TEP-31 Jones Reb. At 13.
[296] The Company originally proposed a 9 month transition period, but indicated it would not object to a 12 month period. Tr. at 2779.
[297] For the "extreme" counter-seasonable customers, the ratchet would be waived for full requirements customers who consume 90 percent or more of their kWh during the winter period.

TEP's proposed the following MGS rates:[298]

Basic Service Charge per Month	$40
Summer Demand Charge per kW	$6.75
Winter Demand Charge per kW	$5.00
Summer kWh	$0.080790
Winter kWh	$0.067790
Base Power Summer kWh	$0.035691
Base Power Winter kWh	$0.032608
PPFAC Charge kWh	$0.000000

TEP generally agrees with Staff's recommendations concerning the transition to the MGS tariff, including keeping the record open for 18 months to account for any unanticipated customer rate impacts. The Company's transition plan includes:

- If the Commission approves the MGS rates, the Company will promptly begin providing information about the new rates to the customers most likely to be migrated.
- Educational materials detailing the new rates will be mailed (via traditional mail and email, if known) to customers, will be available on TEP's website, and included in the Company's business customer e-newsletter.
- SGS customers that qualify for the LGS rate (imputed demand greater than 500 kW) will be moved to the LGS rate with the first billing cycle after the rate effective date.
- SGS customers with usage meeting or exceeding 24,000 kWh in consecutive months will automatically be moved to the MGS rate on the first billing cycle after the rate effective date.
- However, new MGS customers will not immediately experience a demand charge. Instead, a two-part MGS transition rate will apply for the first 12 months. During this period, MGS bills will reflect a $0.0 per kW charge so that customer can begin to track and manage their kW demand.

[298] Ex TEP-32 Jones RJ at CAJ-JR-1 at 19.

- Once the transition period is over the next billing cycle will reflect the final MGS rates.[299]

TEP states that it is willing to provide current SGS customers with DG facilities the option of remaining on two-part rates.[300]

TEP's proposed MGS rate includes a 75 percent demand ratchet which TEP asserts operates as a type of minimum demand charge.[301] TEP states that the ratchets were expanded to the largest customer classes in the last rate case to help mitigate intraclass subsidies.[302] The Company asserts that customers can reduce that minimum charge by reducing their maximum demand during a rolling 11-month period. TEP argues that the alternative to ratchets is to assign these costs to be paid by other customers or create a seasonal rate that recovers these costs by higher charges. TEP argues that the demand ratchet will help ensure that demand revenues will cover demand costs, while also sending appropriate price signals to the medium and large commercial customers to reduce demand over the long run.[303]

TEP asserts that EFCA's and SOLON's concerns about the MGS ratchets are unfounded and ignore their purpose and benefits.[304] TEP states that if ratchets are eliminated, there will be an increase in other rate elements such as the demand rate. Furthermore, TEP argues the concern that the customers who transfer to the MGS Class will not be able to understand or manage demand underestimates those customers. TEP states that it and Staff have agreed to extend the transition period and related customer education plan to 12 months, so that new MGS customers will not be subject to an actual demand charge until the transition plan is complete. With respect to concerns that

[299] Ex TEP-31 Jones Rebuttal at 16-17.
[300] TEP Opening Brief at 33. The two-part rates for the grandfathered DG customers would be the two-part MGS transition rate. TEP Reply Brief at 21.
[301] TEP states that demand charges recover long-term costs of facilities such as wires, poles and generating resources.
[302] TEP Opening Brief at 34.
[303] In preparing its case, TEP identified a small number of potential MGS accounts that are extremely counter seasonal. These customers draw significant power during the low use winter period. To limit the impact of the ratchet on these customers, TEP proposes to amend the MGS tariff to include a seasonality clause for customers who consume 90 percent or more of their kWh during the winter period (October-April). The provision includes: waiving the ratchet mechanism, waiving the MGS cap, and applying section 7.C.7.g of the Company's Rules and Regulations regarding line extensions for "Unusual Loads". This rate will only be available to full requirements customers because according to TEP, even if net metering customers "net meter to zero" through the summer, they draw power during the year and should contribute to their costs to the grid. TEP Opening Brief at 34-35.
[304] TEP Reply Brief at 20.

MGS customers will not be notified if they are eligible to move back to SGS rates, TEP states such notification is not typically done with respect to commercial and industrial rate classes.

Furthermore, TEP states that although Pima County opposes the elimination of the governmental discount, it presented no testimony as to why it should be entitled to a subsidy from other TEP rate payers. TEP states that any reduced cost recovery resulting from the discount would be passed on to other TEP rate payers.[305] Similarly, TEP argues that Pima County provided no evidence explaining why grandfathering governmental facilities on the SGS rate is in the public interest and did not raise this issue until briefing. TEP states that Pima County's late assertions raised in its Closing Brief about governmental customers cannot be tested by cross-examination. TEP believes there are likely some governmental customers that have higher load factors and will benefit from the MGS rates. TEP argues that such limited and potentially discriminatory grandfathering is inappropriate.[306]

b. <u>LGS Rates</u>

TEP proposed the following LGS rates:

Large General Service:[307]

	Current Rates	Proposed Rates	$ Increase	% Increase
Basic Service Charge per month	$775.00	$950.00	$175.00	23%
Demand Charge per kW	$15.25	$17.40	$2.15	14%
Summer kWh	$0.0192	$0.0185	-$0.000670	-3%
Winter kWh	$0.0134	$0.0143	$0.000900	7%
Base Power Summer kWh	$0.035111	$0.035691	$0.000580	2%
Base Power Winter kWh	$0.031532	$0.032608	$0.001076	3%
PPFAC Charge kWh	$0.006820	$0.00000	N/M	N/M

Large General Service TOU

	Current Rates	Proposed Rates	$ Increase	% Increase
Basic Service Charge per month	$950.00	$950.00	$0	0%
Demand Summer On-Peak per kW	$14.55	$22.15	$7.60	52%
Demand Summer Off-Peak per kW	$10.92	$10.92	$0	0%

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305 *Id.* at 19.

306 TEP Reply Brief at 21.

307 Ex TEP-32 Jones RJ at CAJ-RJ-1 at 20. Based on TEP's proposed allocations.

Demand Winter On-Peak per kW	$11.59	$18.50	$6.91	60%
Demand Winter Off-Peak per kW	$9.10	$9.10	$0	0%
Summer On-Peak kWh	$0.008600	$0.018540	$0.009940	116%
Summer Off-Peak kWh	$0.006000	$0.012700	$0.006700	112%
Winer On-Peak kWh	$0.003000	$0.007100	$0.004100	137%
Winter Off-Peak kWh	$0.000500	$0.001250	$0.000750	150%
Base Power Summer On-Peak kWh	$0.050669	$0.071322	$0.020653	41%
Base Power Summer Off-Peak kWh	$0.026679	$0.025609	-$0.001070	-4%
Base Power Winter On-Peak kWh	$0.032893	$0.038010	$0.005117	16%
Base Power Summer Off-Peak kWh	$0.027092	$0.025655	-$0.001437	-5%
PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

The LGS rate will apply to customers with a load of 300 kW to 5,000 kW, and the 75 percent demand ratchet approved in the last rate case will continue to apply. TEP added an off-peak excess demand provision to the LGS-TOU rate in order to be consistent with the currently effective LPS-TOU off peak demand provision.[308]

TEP states that LGS customers generally support the proposed LGS rates, noting that Kroger supports the rate design and Wal-Mart appears to generally support the LGS-TOU rates, but would like a larger amount of the class revenues recovered through the demand charge.[309] TEP states that Wal-Mart's proposal benefits high load factor customers who use the system more efficiently and more accurately reflects the distinction between fixed and variable costs.[310] TEP states that it moved substantially in this direction in its rebuttal position, but not as far as Wal-Mart desires.

TEP notes that SOLON opposed the proposed LGS rate because of fears that the demand rate and ratchet risk curtailing solar and conservation. TEP responds that the current LGS tariff has demand rates and ratchets and several of TEP's current LGS customers have solar and solar penetration has increased in the last two years for both the LGS and LPS classes.[311] TEP asserts that LGS customers always have incentive to conserve energy and demand rates provide the ability to reduce both usage and demand.[312]

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[308] Ex TEP-30 Jones Dir at 35.
[309] Kroger Opening Brief at 2-3; Wal-Mart Opening Brief at 5.
[310] Tr. at 1829.
[311] Ex TEP-32 Jones RJ at 14. In the last two years, LGS customers with solar systems increased from 5.4 percent to 7.1 percent and LPS customers with solar have increased from 11.1 percent to 26.3 percent.
[312] TEP Reply Brief at 21.

c. LPS and 138 kV Rates

TEP proposed the following rates for Large Power Service TOU and the new Transmission Services Rate 138kV which will be available to the Company's largest customers who take service at high voltage and do not cause distribution costs to the system:[313]

Large Power Service TOU	Current Rates	Proposed Rates	$ Increase	% Increase
Basic Service Charge per month	$2,000.00	$10,000.00	$8,000.00	400%
Demand Summer On-Peak per kW	$20.49	$21.55	$1.06	5%
Demand Summer Off-Peak per kW	$12.49	$14.69	$2.20	18%
Demand Winter On-Peak per kW	$15.49	$17.00	$1.51	10%
Demand Winter Off-Peak per kW	$9.99	$14.58	$4.59	46%
Summer On-Peak kWh	$0.006900	$0.007000	$0.000100	1%
Summer Off-Peak kWh	$0.006500	$0.007000	$0.000500	8%
Winer On-Peak kWh	$0.007500	$0.007000	-$0.000500	-7%
Winter Off-Peak kWh	$0.007100	$0.007000	-$0.000100	-1%
Base Power Summer On-Peak kWh	$0.045568	$0.052350	$0.006782	15%
Base Power Summer Off-Peak kWh	$0.023985	$0.025760	$0.001775	7%
Base Power Winter On-Peak kWh	$0.029581	$0.033550	$0.003969	13%
Base Power Summer Off-Peak kWh	$0.024352	$0.025660	$0.001308	5%
PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

138kV[314]	Proposed Rates
Basic Service Charge per month	$15,000.00
Demand Summer On-Peak per kW	$19.72
Demand Summer Off-Peak per kW	$14.69
Demand Winter On-Peak per kW	$17.00
Demand Winter Off-Peak per kW	$14.58
Summer On-Peak kWh	$0.007000
Summer Off-Peak kWh	$0.007000
Winer On-Peak kWh	$0.007000
Summer Off-Peak kWh	$0.007000
Base Power Summer On-Peak kWh	$0.051300
Base Power Summer Off-Peak kWh	$0.024990
Base Power Winter On-Peak kWh	$0.032880
Base Power Summer Off-Peak kWh	$0.024890
PPFAC Charge kWh	$0.000000

[313] Ex TEP-32 Jones RJ at CAJ-RJ-1 at 22.
[314] The precursor to the 138 kV rate4s was the LPS TOU- High Voltage rate which had a BSC of $3,000.

TEP proposed to modify the LPS-TOU rate and eliminate the standard LPS rate. The last customer on the standard LLP-14 (Rate 14) moved to the equivalent TOU rate, and believes Rate 14 is unnecessary.[315] No party objected to the proposed elimination of LLP-14. In addition, TEP proposes to change the way the demand charge is applied and billed in the large power tariffs (Rates LPS-90 and 138 kV). The proposed method will "track the amount a customer's monthly power factor varies from 100 percent and applies the current tariff's demand charge to the equivalent demand calculated from the power factor variance from 95%."[316] TEP will also apply the provision in its Rules and Regulations that allows the Company to require installation of power factor correcting equipment on a regular basis, if the provision in the tariffs does not encourage the customers to operate at improved power factors.

TEP notes that not all customers in the LPS class own their own transformers, and argues that these transformer costs should not be allocated to other classes. TEP states that although AECC recommends a special "upcharge" for LPS customers that use TEP transformers, it does not propose a specific charge.[317] TEP argues that the "upcharge proposal would be difficult to administer, and that the better alternative is to include the transformer costs of the LPS class in the rates of that class.

TEP has one customer – Freeport- that takes service at transmission level voltage. TEP sold Freeport certain facilities to facilitate this service, and now proposes a new 138 kV rate that excludes distribution system costs and distribution line losses. The new rate will be offered to customers taking service at a delivery voltage of 138 kV or higher and delivered at a single point of service.[318] Customers taking service at this rate are subject to a 10,000 kW minimum monthly billing demand.

d. Community Solar Rate

TEP is proposing to update its Community Solar rate. Under this program, customers can purchase blocks of electricity from solar generation sources. The existing rate will be locked in place for the remainder of the customer's 20-year agreement, but a new rate will be calculated based on the revised class level base fuel cost. Using the same process employed in the last rate case, the new rate will have the same, Commission-approved, $0.02 per kWh premium added and will be available to any

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[315] Ex TEP-30 Jones Dir at 46.
[316] TEP Opening Brief at 37-38; *See* Ex TEP-30 Jones Dir at 35.
[317] Tr. at 1075-77.
[318] Ex TEP-30 Jones Dir at 56.

customer signing up for the program after the effective date of the new rates.

The existing frozen Community Solar rates have a 20-year term and are based on fuel costs established in prior rate cases. Customers being migrated from the current SGS rate to the MGS rate, will pay the MGS delivery rates, but be allowed to maintain the fixed Community Solar rate for the energy blocks they currently have.[319] These customers will only need to pay the new MGS Community Solar rate if they choose to purchase new blocks or replace blocks they dropped.

2. AECC/Freeport/NS

AECC/Freeport/NS assert that their rate design proposal corrects several distortions contained in TEP's original CCOSS.[320] They state that because the customer related components on Schedule G-6-1 for the LPS and 138kV classes are inflated and inconsistent with the composition of allocated costs on Schedules G-3 and G-4, that TEP's proposal to increase the BSC for LPS and 138kV customers from $2,000 to $10,000 and from $3,000 to $15,000 per month, respectively, should be rejected.[321]

AECC/Freeport/NS recommended the following LGS, LPS-TOU, and 138 kV rates:[322]

Large General Service TOU

	Proposed Rates
Basic Service Charge per month:	
Meter Services	$157.10
Meter Reading	2,58
Billing & Collection	48.68
Customer Delivery	741.64
Total	$950.00
Demand Charge Components (per kWh)	
Delivery Charge[323]	$1.97
Generation Capacity	$13.10
Fixed Must-Run	$1.64
Total Transmission	$4.36
Total Demand Charge	$21.07
Transmission Charge Components ($/kW)	
FERC Transmission Rate	$3.39
Ancillary 1: System Control $ Dispatch	0.05

[319] *Id.* at 54.
[320] AECC/Noble Solutions Opening Brief at 13.0.05
[321] Ex AECC-10 Higgins Surr at 30.
[322] *Id.* at KCH-SR-1 (based on their revenue allocations).
[323] AECC/Freeport/NS state that the Unbundled Delivery demand charge is designed such that the combination of Basic Service Charge and Delivery demand charge revenues are proportionate to Distribution costs.

Ancillary 2: Reactive Supply and Voltage Control	0.18
Ancillary 3: Regulator $ Freq. Response	0.18
Ancillary 4: Spinning Reserve Service	0.48
Ancillary 5: Supplemental Reserve Service	0.08
Total Transmission	4.36
Energy Charge Components ($/kWh)	
Local Delivery – Summer	$0.00000
Local Delivery – Winter	$0.00000
Base Power Supply Charges ($/kWh):	
Base Power Supply Summer	$0.035868
Base Power Supply Winter	$0.032537

	LPS-TOU	LPS-138kV
Basic Service Charge per month:		
Meter Services	$488.53	$348.37
Meter Reading	8.19	82.10
Billing & Collection	149.70	1,228.02
Customer Delivery	1,353.58	1,341.51
Total	$2,000.00	$3,000.00
Demand Charge Components ($/kW)		
Local Delivery		
Summer On-Peak	$3.97	$0.01
Summer Off-Peak	1.62	0.01
Winter On-Peak	2.74	0.01
Winter Off-Peak	0.69	0.01
Generation Capacity		
Summer On-Peak	$8.76	$7.58
Summer Off-Peak	3.58	3.72
Winter On-Peak	6.05	5.71
Winter Off-Peak	1.31	1.19
Fixed Must Run	$1.50	$1.47
Transmission Charge Components ($/kW)		
FERC Transmission Rate	$3.39	$3.23
Ancillary 1: System Control $ Dispatch	0.05	0.04
Ancillary 2: Reactive Supply and Voltage Control	0.18	0.17
Ancillary 3: Regulator $ Freq. Response	0.18	0.17
Ancillary 4: Spinning Reserve Service	0.48	0.45
Ancillary 5: Supplemental Reserve Service	0.08	0.07
Total Transmission	$4.36	$4.13
Total Demand Charges ($/kW)		
Summer On-Peak	$18.59	$13.19
Summer Off-Peak	11.06	9.33
Winter On-Peak	14.65	11.32
Winter Off-Peak	8.06	6.80
Generation Energy Charge Components ($/kWh)		
Summer On-Peak	$0.00780	$0.00780
Summer Off-Peak	$0.00780	$0.00780

Winter On-Peak	$0.00780	$0.00780
Winter Off-Peak	$0.00780	$0.00780
Power Supply Charges ($/kWh)		
Base Power Supply Charges		
Base Power Supply Summer On-Peak	$0.049077	$0.048044
Base Power Supply Summer Off-Peak	$0.025413	$0.024878
Base Power Supply Winter On-Peak	$0.032198	$0.031520
Base Power Supply Winter Off-Peak	$0.026687	$0.026126

In addition, AECC/Freeport/NS assert that TEP allocates the cost of distribution transformers to members of the LPS class, even though 12 of the 18 customers in this class own their own transformers.[324] AECC/Freeport/NS contend that TEP has refused to accept AECC's correction even though the Company's witness testified it would be a cost-shift that should be avoided.[325]

AECC/Freeport/NS also argue that TEP overstates distribution charges and understates generation charges in its unbundled rate design.[326] AECC/Freeport/NS state that TEP did not update its unbundled rates despite conceding that additional costs can be moved to the generation component of the rate as advocated by Mr. Higgins.[327] AECC/Freeport/NS recommend that the Commission approve the modifications to the unbundled rates as presented in Mr. Higgins' Surrebuttal Testimony, adjusted for the final class revenue requirements, and require TEP to correct the depiction of classified and functionalized costs in its CCOSS in its next rate case.

3. Kroger

Kroger supports the Company's proposed rate design for LGS-TOU as shown in Craig Jones' Rebuttal Testimony. Kroger states that the Company addressed Kroger's concerns that the LGS-TOU rates did not reasonably balance cost recovery through volumetric and demand-based charges by placing more of the increase on the demand charges rather than in the energy charges. Kroger states that the revised rate design limits the amount of intra-class subsidies that would be paid by higher load factor LGS customers to the lower load factor LGS customers.[328]

Kroger no longer believes that the Commission should address a Multi-Site Commercial Rate in this proceeding.[329]

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[324] AECC/Freeport/NS Opening Brief at 13.
[325] Tr. at 766.
[326] AECC/Freeport/NS Opening Brief at 13; Ex AECC-10 Higgins Surr at 31.
[327] AECC/Freeport/NS Opening Brief at 13-14; Ex AECC-10 Higgins Surr at 31.
[328] Kroger Opening Brief at 2.
[329] *Id.* at 3.

4. EFCA

EFCA argues that TEP has not offered a compelling reason why the MGS Class is necessary, nor met its burden to prove that the proposed MGS rate is just and reasonable.[330] EFCA argues that the MGS Class should not be formed and the Commission should consider an alternative to demand ratchets for the LGS Class.[331] EFCA contends that because they are set based on energy usage during a short period of time, demand charges are volatile, and customers are more likely to encounter higher monthly bills with demand charges than with traditional two-part rates or TOU rates. EFCA argues that demand ratchets exacerbate the problem because under a standard demand charge, a single instance of high demand can set a large part of the bill for a single month, but under a ratchet, the single instance of high demand can set a large part of the bill for an entire year.

EFCA asserts that TEP's proposed demand ratchet would be particularly difficult for customers to manage because it is not time-of-use-based, but instead based on non-coincident fifteen minute intervals. Thus, a customer must manage 35,040 intervals over the course of a year because any one of them could end up setting the annual demand ratchet.[332] Further, EFCA states, the ability to manage demand is further complicated because TEP does not have metering infrastructure in place that is capable of providing instantaneous demand data to the customer. EFCA claims that it is uncommon for smaller commercial customers to be subject to demand charges, let alone demand ratchets. EFCA states that typically when demand ratchets are imposed, they apply to rate classes with a small number of very large customers, whose individual load profiles are analyzed prior to designing the ratchet. In this case, EFCA states TEP has not analyzed the load profiles of the potential customers in the proposed MGS class at all.[333] EFCA asserts that the only purpose of the MGS class is to expand the use of ratchets and there is no legitimate need for the MGS class.[334]

EFCA also asserts that typically utilities that pursue demand charges (and ratchets) do so as a method of "peak shaving," and set the charge to coincide with the utility's peak demand, so that the

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[330] EFCA Reply Brief at 2.
[331] EFCA Opening Brief at 2.
[332] Tr. at 2263-2264.
[333] Tr. at 2308.
[334] EFCA Reply Brief at 3.

demand charge sends a price signal to reduce demand at peak times.[335] EFCA argues that TEP's non-coincident peak proposal does nothing to reduce peak demand, and in fact, the ratchet could be set even when TEP's system is experiencing very low overall demand.[336] EFCA asserts that such a circumstance would result in TEP over-collecting fixed demand-related costs from customers that exhibit the exact behavior the utility is seeking to incentivize—shifting load away from the system peak.

EFCA argues that demand ratchets discourage energy efficiency and storage technologies because once the minimum demand and a portion of the bill is set for the next 12 months, behavioral changes will have no effect. Further, EFCA claims that demand ratchets are incompatible with battery storage technology and contradict TEP's stated goal of designing rates that provide the "right economic incentives for the development of cost-effective energy technologies, such as storage."[337] EFCA notes that RUCO's witness Huber testified that a year-round demand ratchet would "kill storage right out of the gate."[338] TEP's Mr. Jones testified that ratchets only discourage storage if the customer in question reached peak demand outside the period when storage was utilized, but later admitted that it may not completely mitigate the problem, and agreed that for customers with a high load factor and steady usage, storage would not help mitigate the effect of the ratchet.[339] In addition, because the ratchet sets a minimum demand for the year, any one implementing energy efficiency or storage would need to wait a year before seeing the benefits of the investment. EFCA argues that the delay is not just an inconvenience, but a deterrent to adoption.[340]

EFCA further argues that demand ratchets are poor public policy, and advocates implementing an alternative to the existing demand ratchet for the LGS Class. EFCA proposes that TEP reform the existing LGS tariff to assess monthly demand based on the maximum monthly 15-minute interval demand.[341]

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335 EFCA Opening Brief at 3.
336 Tr. at 2023-2025.
337 Ex TEP-4 Hutchens Dir at 23.
338 Tr. at 1574.
339 EFCA Reply Brief at 8; Tr. at 2042.
340 EFCA Reply Brief at 8.
341 *Id.* at 7.

EFCA asserts that the absence of an education plan for prospective MGS customers is alarming and the Company's customers are unprepared for demand ratchets. EFCA criticizes TEP's tentative transition plans because TEP has not yet clearly identified which customers would be switching into the new rate class, and after the transition period, new members of the class would not have any transition period. [342] Furthermore, EFCA states, TEP has only engaged in informal customer outreach and has not even contacted half of the potential customers to be moved into the MGS Class, nor can TEP identify which customers have been contacted.[343] EFCA argues that the transition plan contemplates minimal outreach consisting of sending letters to affected customers.[344] EFCA believes that notifying SGS customers who are poised to reach the MGS threshold usage by letter is ineffectual because by the time the customer receives notice, there will be little time to adjust their behavior to avoid being bumped into the MGS Class.[345] EFCA asserts that most of the 4,000 potential MGS customers have had no notice of the proposal and thus no opportunity to voice their concerns. EFCA argues that customers should be afforded no less than 12-months to transition to demand charges in order to have an understanding of their demand patterns.[346]

EFCA argues that small business customers cannot and will not be able to manage demand ratchets. EFCA states that demand rates make it more difficult for customers to control their bills because the customer does not know their actual demand until peak demand has already been set. TEP's billing system provides demand data at the end of the month, and its web portal, once in place, would not provide instantaneous data.[347] EFCA argues that it is unacceptable that customers would not have access to interval data on a timely basis because the customer needs to know how demand is changing throughout the intervals in order to know how to change behavior. EFCA argues that a bill that only indicates the peak demand does not tell the customer anything about the relevant usage and whether shifting usage would have made a difference.[348]

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[342] EFCA Opening Brief at 6; Tr. at 2019 & 2820.
[343] Tr. at 2020-2022.
[344] EFCA Opening Brief at 7.
[345] *Id.*
[346] *Id.* at 8.
[347] Tr. at 2031.
[348] EFCA Opening Brief at 9.

EFCA characterizes the MGS Class as a trap with no way to escape.[349] EFCA argues that TEP has not developed a clear way to leave the class, and even if a customer were to maintain usage below the 24,000 kWh for an entire year, the customer would not be reverted to SGS automatically, nor would TEP notify them, but they would only be permitted to switch upon request. [350] EFCA argues that the problem needs to be addressed because TEP "should not have authority to pick and choose which customers are subject to demand ratchets and which are not."[351]

EFCA argues that Staff's proposed safeguards do not cure the MGS transition plan as they do not provide sufficient notice or safeguards to be effective.[352] Staff also recommends that TEP develop a cost of service study for the MGS class in the next rate case and that TEP provide free interval data to MGS customers for six months after the transition.[353] EFCA responds that unfortunately TEP cannot provide consumption or interval data to MGS customers because it does not have the metering capability.[354] EFCA criticizes the timing of Staff's proposal because it is not useful to gain access to consumption and interval data after consumption has occurred and peak demand is set. In addition, EFCA argues that Staff's proposal seems to assume that at some point after six months, customers will have to pay for the information. EFCA asserts that forcing customers to pay an unknown charge for critical data is not a safeguard. Further, EFCA believes that requiring a cost of service study after the rates have been in effect for years is unreasonable.

5. SOLON

SOLON's concern in this rate case focused on the proposed changes to the rate plans for all small and medium-sized businesses, regardless of whether or not they maintain DG systems. SOLON states that as a developer and contractor of commercial and utility scale solar power systems, its interests are focused on its current and potential customers which include a broad array of businesses, educational facilities, non-profits, municipalities, counties and non-profit organizations.[355] In this phase of the proceeding, SOLON focused on its concerns on those commercial customers that would

[349] *Id.*
[350] Tr. at 2818-2819.
[351] EFCA Opening Brief at 10.
[352] EFCA Reply Brief at 5.
[353] Staff opening Brief at 18.
[354] Tr. at 2256.
[355] SOLON Opening Brief at 3.

be forced to transition from the current GS-10 rate to one of the following plans: MGS, MGS-TOU, LGS, or LGS-TOU. SOLON is concerned that the forced transition will lead to highly unpredictable and drastically increased rates, and that the proposed 75 percent demand ratchet on lower load customers will lead to unpredictable and high rate increases for a large number of customers while not serving its purpose to decrease peak demand. SOLON argues that these issues apply to all customers, but disproportionately affect solar DG customers and that the Company has not provided sufficiently complete, unaltered and non-aggregated data to determine the bill impacts on the affected customers. Thus SOLON recommends:

(1) Rejecting the proposal to involuntarily transition customers from the current GS-10 rate to the proposed MGS and LGS rate plans; but if the Commission determines that the MGS transition should proceed that TEP should be ordered to provide alternative two-part TOU plans prior to the expiration of the any transition period, and MGS and LGS customers should be allowed to choose among these plans.

(2) Rejecting the proposal to use demand ratchets for low load MGS customers; and

(3) Prior to the Decision in this case, TEP should be required to release monthly billing determinants for each customer expected to transition to the MGS and LGS rate plans so that the parties can further validate the expected impacts on TEP's proposals.[356]

SOLON argues that not having access to interval data indicates that the Company has not sufficiently analyzed the proposed rate designs and further that the Company's proposed implementation plan which involves mailing educational materials, providing information on the Company's website, and outlining the proposed rate design in business customer newsletters is not sufficient given the complexity of the plans. In addition, SOLON argues that commercial or public sector customers do all not have utility experts who can advise them how to control demand or usage. SOLON argues that customers will have difficulty assessing the amount or timing of demand.

SOLON notes that the Company has stated that it will give the affected customers notice of the transition as soon as the Company has record of the increased consumption and the change will be

[356] SOLON Reply Brief at 2. *See also* SOLON Opening Brief at 5.

effective in the subsequent billing cycle.[357] SOLON asserts it is problematic that there is no formal procedure for customers to object to or appeal the transition, and especially if customers are forced onto the LGS plan, with a fixed monthly cost of $950, and minimum demand cost of $5,220, and an annual demand ratchet of 75 percent of peak demand, the bill impact on customers with a current $30 fixed charge, no demand charges and no demand ratchet would be drastic and contrary to concepts of gradualism.[358]

Further, SOLON argues that because the Company does not have enough interval data to analyze, the true impact of the rate plans for many customers remains unknown. SOLON states that the Company has not conducted a case-by-case, thorough impact analysis using unaltered and non-aggregated interval data, to assess the true impacts of the proposed rate plan changes. SOLON's analysis of 378 customer profiles indicates that 93 percent fell outside of the Company's projected 2.2 percent to 5.1 percent bill impact.[359] SOLON argues that when 93 percent of an approximately 10 percent sample size reveals that the impact is consistently different, the Company's conclusion of the bill impact merits closer analysis.[360]

SOLON argues that the proposed transition to the MGS or LGS rate plans would completely erode the economic value of commercial customers' investment in the solar DG, and thus, would curtail the growth of solar and conservation.[361] SOLON notes that in its Opening Brief TEP proposed to grandfather DG customer who qualify for the MGS plan for a period to be determined in Phase 2 of this proceeding.[362] SOLON views the proposal as a step in the right direction, but notes it should also apply to existing DG customers that will be transitioned to the LGS class.[363]

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[357] Tr. at 2540-2541.

[358] SOLON Opening Brief at 11. SOLON illustrated its point with a hypothetical: "Imagine the commercial customer that has usage of 12,000 kWh in month one, 12,500 kWh in month two, and for a variety of reasons, is able to decrease its consumption to 11,000 kWh per month for the remainder of the year. This customer would be forced onto the MGS rate plan for at least a year, which may, in turn, result in drastically higher rates."

[359] SOLON Opening Brief at 12; Ex SOLON-6; Tr. at 2542. According to SOLON's analysis, some customers saw a 54 percent bill increase while others saw a 10 percent bill decrease.

[360] SOLON believes that a larger sample size is necessary.

[361] SOLON Opening Brief at 14-15.

[362] SOLON Reply Brief at 6; *see* TEP Opening Brief at 33.

[363] SOLON Reply Brief at 6. SOLON notes that the two examples in Mr. Seibel's Surrebuttal Testimony in which a health care facility and local church were projected to experience increases of 3,654 percent and 420 percent were due to the transition from GS-10 to LGS.

Finally, SOLON argues that the effects of the ratchet are punitive and arbitrary. SOLON states that faced with a 75 percent ratchet, a customer may struggle to avoid activities that may trigger a higher ratchet, but once imposed, the customer has no incentive to decrease overall usage since it pays the ratchet for a year. Further, SOLON argues that TEP has not demonstrated that the proposed seasonality clause will adequately mitigate unreasonable impacts.[364] SOLON notes that the seasonality clause excludes DG customers, who SOLON asserts will see impacts in excess of 100 percent.[365] SOLON also argues the seasonality clause would not address unreasonable impacts to seasonal customers with a longer season.

SOLON argues that the proposed transition plan only delays the unreasonable impacts for a short time, without giving affected customers who are unable to reduce their peak demand a reasonable option. SOLON argues that rather than the proposed transition plan, it would be more effective to either: (1) provide MGS and LGS customers with permanent alternative rate options that include two-part rates plans; or (2) rejecting the involuntary transition to three-part demand rates, and be provided with other rate plan options within their rate class.[366]

6. <u>Koch</u>

Mr. Koch states that TEP's proposal to transfer GS-10 customers who use more than 24,000 kWh during any two consecutive months to a rate with a lower volumetric charges but with demand charges would result in some customers paying more for their solar lease payments or financing terms than they are saving on their electric bills.[367] He says that this could apply to customers who purchased a solar energy system that was only designed to produce a portion of their electricity use, or to customers who have much higher summer use and whose average solar production is 12,000 kWh/month less than their summer usage. Mr. Koch asserts that these rate structures may be acceptable for future solar customers, but that applying these rates to customers who adopted solar under the old rate structure, runs the risk of changing the rules mid-stream and harming customers who the Commission had earlier encouraged to adopt solar. Mr. Koch urges the Commission to allow existing

[364] SOLON Reply Brief at 7.
[365] Ex SOLON-4 Seibel Dir. at 43-45.
[366] SOLON Reply Brief at 7.
[367] Koch Opening Brief at 2.

commercial solar customers to retain the GS-10 rate structure regardless of their size until 20 years after the commissioning of their solar electric systems.

7. Pima County

Pima County states that TEP provides electrical power to a substantial portion of Pima County, including Pima County-owned facilities such as courts, jails, emergency communications, governmental offices, libraries, parks, schools, social service agencies, sports, traffic signals and lights, health clinics, and water reclamation facilities. Except for the County's Regional Wastewater Reclamation Department, utility costs for these facilities are paid for by monies generated through property taxes. Pima County explains that currently it receives service under TEP's GS-10 rates, and receives a 16.5 percent discount. In this case, TEP proposes to eliminate the discount. In addition, TEP proposes to transfer all customers using 24,000 kWh or more in a two month period to a new MGS class, which would have substantially higher fixed fees, lower volumetric charges, and also a ratchet mechanism for demand charges.[368] Pima County argues that TEP's proposals will cause major financial hardship for Pima County and should be rejected.[369]

First, Pima County argues that TEP should maintain the current municipal discount because it provides societal benefits. The County states that TEP's justification for eliminating the discount on the grounds that "[m]unicipal customers enjoyed a substantial subsidy without providing any system benefits that justified the subsidy" and "to take the next step towards bringing municipal customers' rates in line with other similarly situated customers" is not in the public interest in this case.[370] TEP has estimated that the combined impact of the proposed increase in SGS rates and the elimination of the municipal discount is approximately $2.2 million per year on Pima County alone.[371] Pima County asserts that to cover the increased electricity costs during the current fiscal year, the County will likely need to reduce or eliminate funding for current programs, and in future years, the County will have to

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[368] Pima County Opening Brief at 1.
[369] Staff Opening Brief at 18.
[370] Ex TEP-30 Jones Dir at 11. Pima County Opening Brief at 2.
[371] Pima County states that this estimate was prior to the Settlement Agreement, and that the post-Settlement Agreement impact is not clear. However, Pima County compared Mr. Jones' Direct Testimony which showed a 30 percent increase in the rate of GS-10 municipal customers, with Mr. Jones' Rejoinder Testimony which indicates a 25.3 percent increase based on the revised revenue requirement. Pima County Opening Brief at 2, citing Tr. at 2656 Ex TEP-30 Jones Dir at CAJ-2, Ex TEP-32 Jones RJ at CAJ-RJ-2.

choose between eliminating programs and raising taxes. Pima County asserts neither option is in the public interest.

Pima County also argues that TEP has expressed support for Bonbright's principles of rate making, but its proposal is contrary to the principle of gradualism, under which consideration should be given to "[s]tability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers."[372] Pima County states the municipal customers will be hit with 25.3 percent increases in just the fixed and volumetric rates.

Pima County also argues that the new MGS class should not be applicable to governmental customers. Pima County states that approximately 70 County metered locations would be transferred to the new MGS tariff under TEP's proposal. The County states that its facilities are not able to readily adjust power needs, but must remain open and available during normal hours of operation and do not have the ability to adjust either total power usage or peak demand.[373]

Pima County states that TEP is selling the concept of demand charges and ratchets for the MGS class as a way to provide more stability in recovering fixed charges, and suggesting that customers will have the opportunity to modify their capacity needs and usages and save money; and further that many of the new MGS customers will be happy with a three-part rate because their bills will go down.[374] Pima County claims this will not be the case for most governmental meters because they are locked into usage patterns and have limited capacity to modify electrical infrastructure. The County further argues that TEP's proposed demand charge exacerbates that situation because it drains funds that could otherwise be used for infrastructure improvements.[375] The County argues that the ratchet that locks in a minimum demand charge regardless of usage, variations in usage, or efforts to conserve, and they place many MGS customers, and especially governmental MSG customers, into an untenable position with no way to mitigate demand charges.

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[372] Bonbright, James C., Principles of Public Utility Rates (1988).
[373] Pima County Opening Brief at 4.
[374] Tr. at 2566 and 2592.
[375] Pima County Opening Brief at 5.

8. Wal-Mart

Wal-Mart primarily takes service under the Large General Service Time of Use Rate (""LSG-85").[376] Wal-Mart notes that TEP is proposing to collect a majority of the subsidy allocated to the LGS class through the energy component of the bill. Wal-Mart states that TEP's proposed LGS rates are designed to collect about $30 million, but that the only applicable costs to be recovered through the energy component is $223,000 in uncollectible costs (because fuel costs are collected though the base power charges in the rate).[377] Wal-Mart asserts that subsidies should be collected through fixed charges, and thus proposes that the LGS-85 tariff be re-designed to collect subsidies through the demand component of the bill rather than through the kWh energy charge component.[378] Wal-Mart recommends that the kWh delivery charges be adjusted downward to collect only the costs associated with uncollectables and the on-peak demand charge be adjusted to replace the revenues no longer collected through the kWh charges.[379] Mr. Tillman proposed the following LGS rates (based on the Company's direct case revenue):[380]

LGS-TOU

Basic Service Charge per month	$1,000
Demand Summer On-Peak per kW	$29.41
Demand Summer Off-Peak per kW	$10.92
Demand Winter On-Peak per kW	$26.91
Demand Winter Off-Peak per kW	$9.10
Summer On-Peak per kWh	$0.00015
Summer Off-Peak per kWh	$0.00015
Winter On-Peak per kWh	$0.00015
Winter Off-Peak per kWh	$0.00015
Base Power Summer On-Peak kWh	$0.06080

[376] Ex Wal-Mart-1 Tillman Rev.Dir at 3.
[377] Ex Wal-Mart-2 Tillman Rate Dir at 17.
[378] Wal-Mart Opening Brief at 5; Tr. at 1820.
[379] Ex Wal-Mart-2 Tillman Rate Dir at 18.
[380] *Id.* at GWT-5.

Base Power Summer Off-Peak kWh	$0.02570
Base Power Winter On-Peak kWh	$0.05600
Base Power Winter Off-Peak kWh	$0.02210

9. Staff

Staff supports establishing the MGS class as proposed by the Company with proposed safeguards. Staff recommends that the Company be required to develop and implement an MGS cost of service class in the next rate case to verify the costs to be used in the future MGS rate design. Staff also recommends that the Company provide consumption and interval data to MGS customers free of charge for a period of 6 months after the mandatory transition of MGS customers. In addition, since changes to rate design may have unintended results for "outlier" or "non-normal" MGS customers, and the imposition of a demand ratchet may also have unforeseen impacts, Staff recommends that the Commission should keep the rate design portion of this rate case open for at least 18 months after the completion of the transition to MGS rates. [381]

10. Analysis and Resolution of MGS, LGS, LPS-TOU and 138 kV Rate Design

TEP has demonstrated a need for the creation of a new MGS Class for those commercial customers with usage above 24,000 kWhs in two-consecutive months and demands between 20 and 300 kW. The current GS-10 Class is so broad that it leads to intra-class subsidies and resultant inequities. The proposed transition, from a standard two-part rate to a three-part rates with a demand ratchet is a substantial change for the affected commercial customers who may or may not be sophisticated energy users. TEP did not provide substantial information about who these 4,000 customers are. TEP states it will provide a 12-month transition plan to assist customers become familiar with the new rate design, but a specific detailed plan was not entered into the record. TEP proposed that current DG customers who would be transitioned to the MGS Class would be able to remain on the two-part MGS transition rates for 20 years after the time they interconnect.

Customers transitioning from the current GS-10 rate to the new MGS rate will experience an increased BSC from either $15.50 or $20.50 to $40, and a new demand charge and ratchet

[381] Staff Opening Brief at 18.

mechanism.[382] For the first 12 months after approval of a detailed transition plan, the new MGS members would remain on two-part transition rates, but would be provided information about their demand on their bills, although it is unclear how the customer would translate the information into a bill impact.[383] At the time of the hearing, TEP could not provide a web-based portal for customers to access their demand history, but was planning to give its customers on-line access at some point.[384]

Demand charges are not unusual in the commercial arena. In this case, the proposed MGS rate design is reasonable except for the ratchet that adds a level of complexity and potential unfairness to a class of customers who are new to demand charges. The proposed 75 percent ratchet provides a floor demand charge. As we noted in the UNSE rate case, we have concerns about ratchets and believe that seasonal, and or time-of-use demand charges, can provide a more equitable solution to reliable cost recovery. We are not convinced that applying a demand ratchet to the new MGS class is reasonable. We do not have complete information about who these customers are going to be, and are concerned that there will be a wide range of load factors and usage patterns, resulting in large bill impacts. Ratchets might make sense for large customers which tend to have high load factors, but not for smaller customers, and especially not for customers who do not have prior experience with demand charges. The more reasonable course is to accustom these customer to demand rates prior to complicating the experience with ratchets. In TEP's next rate case, we direct the Company to consider and provide testimony on the use of seasonal and time of use demand charges as an alternative to ratchets.

Because TEP did not have a detailed transition plan in place at the time of the hearing, the transitional two-part MGS rates should remain in effect for 12 months after the Commission has approved a detailed transition plan, which should include how TEP will communicate with affected customers, what demand information will be made available, and how it will be accessed, as well as possible training/education modules, and a plan for the transition of existing GS customers whose increased consumption qualifies them for the MGS Class in the future. All current DG customers who qualify for the MGS Class will be defaulted to two-part rates for a period of 20 years from the date

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382 Of course, the new SGS rate will also include an increased BSC on account of the rate increase approved in this proceeding.
383 Tr. at 2564
384 Tr. at 2579-2580 and 2797-98.

they submit an application to interconnect, but shall have the option to adopt the three-part rates. New MGS DG customers shall be subject to the MGS rate design and rates in effect at the time they submit their applications to interconnect. In addition, TEP has proposed that any MGS customer that exceeds the 300 kW cap for a second billing month in a 12-month rolling period will automatically be moved in a subsequent month to the LGS Class, TEP has stated that it will communicate with the customer in writing after the first month they exceed the cap to warn them that if they exceed the cap again during the next 11 months, they will be moved to the LGS Class.[385] We believe this plan is reasonable and TEP should include the process in its transition plan.

Pima County did not provide testimony in this proceeding, and the record does not indicate why a governmental discount was originally approved, but there is no doubt that eliminating the current 16.5 percent government discount will substantially affect these customers. The immediate elimination of this substantial discount would violate the principle of gradualism. Consequently, we will reduce the governmental discount to 12 percent, which retains approximately 75 percent of the current discount. The principle of gradualism must be coupled with our commitment to reducing cross-subsidization across rate classes. Consequently, we adopt an additional 25 percent step-down mechanism, thereby reducing the governmental discount by 25 percent each year until the next rate case. Within 12 months of the effective date of this Order, TEP shall submit to the Commission a POA that details how the additional revenues TEP recovers as a result of the declining discount will be returned to other customers. Other customers in the various classes will be subsidizing the government discount, although to a lesser extent than under the current rates. In its next rate case, TEP should provide testimony on the reasons for this discount and whether or not its continuation is in the public interest.

Based on the totality of circumstances in this case, we find that the proposed LGS rate design is reasonable as presented in TEP's rejoinder testimony, after adjusted to reflect the revenue allocation approved herein. TEP adjusted its proposed rates in response to concerns of Kroger and Wal-Mart, even if its proposal did not go as far as these consumers advocated.[386]

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[385] Ex TEP-31 Jones Reb at 13.

[386] Wal-Mart did not update its initial rate proposal to reflect the Settlement Agreement's revenue requirement, and it is unclear what specific rates Wal-Mart seeks now and what impact such rates would have.

We find further that the proposed increase in the BSC for the LPS-TOU and 138 kV Classes to $10,000 and $15,000, respectively, is unreasonable, as it is many times the current charges. The rates for the largest customers already incorporate a demand component to recover these costs. For the LPS-TOU, we approve a BSC of $2,000 per monthly, and for the 138 kV Class, we approve a BSC of $3,000, which are the same as the current rates and reflect the recommendation of Mr. Higgins for AECC.

We concur with Staff's recommendations that the rate design portion of this case be held open for 18 months after the effective date of this Order for all rate classes in order that we can address any unintended consequences that may result from the rate designs approved herein.

V. Miscellaneous Tariff Issues

A. Proposed Buy-Through Tariff

1. TEP

One of the requirements of the settlement agreement approved in the Fortis/UNS Energy merger was for TEP to present a Buy-Through Tariff in its next rate case. Thus, as part of its current Rate Application, TEP prepared Experimental Rate Rider-14 Alternative Generation Service. TEP modeled Rider-14 after APS's AG-1 program scaled down for TEP's smaller size. TEP does not support adopting Rider-14, or any of the alternative proposals made in this case, arguing that it is premature to adopt a similar program until the results of the APS experiment are known and analyzed.[387]

As proposed, Rider-14 would allow customers taking service under the LPS-TOU or LPS-TOU-HV rates[388] with peak loads of 3,000 kW or more to obtain energy in the competitive market. TEP would contract with the third-party provider and would deliver the energy to the customers. Total participation under Rider-14 is limited to 30 MW of customer load, and if demand for the program is greater than 30 MWs, there would be a lottery to determine which customers can participate. The customer will not pay TEP's Base Power Charge or be subject to the PPFAC. TEP will assess a monthly management fee of $0.0040 per kWh. The customer would be permitted to return to the TEP system with at least one year notice and will be charged $20 per MWh until the customer is fully reintegrated

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[387] TEP Opening Brief at 41-42.
[388] Precursor to the new 138 kV class.

or one year. The returning customer also pays for all fixed generation costs avoided by the customer during the time the customer received service under the Rider.[389]

TEP argues that the Commission should wait until the AG-1 experiment is fully examined in the APS rate case before ordering anther "risky experimental" rate rider with the potential to harm other customers.[390] TEP contends that the initial results of the AG-1 experiment are concerning because APS has reported significant losses, high costs and other problems, and opposes continuation of the program.[391]

TEP concedes that a buy-through would benefit those able to participate in the program, but argues that it would harm other customers by: (1) increasing the average cost of TEP's generation supply by eliminating low cost purchased power resources; (2) shifting fixed generation costs to other customers; 3) creating returning customer risk; and (4) subjecting TEP to counterparty risk with the buy-through provider.

TEP asserts that any buy-through tariff will harm other customers because giving certain larger customers access to the currently low wholesale power market will raise costs for all other customers by leaving them with the burden of the fixed cost component of power prices.[392] TEP states that with the wholesale market at historic lows, it is easy to understand the short-term appeal that a buy-through has to offer large commercial and industrial customers, and currently all of its retail customers see the benefits of the current market prices through the PPFAC. TEP asserts that under the buy-through program, the benefits would only be available to a select class of customers. TEP claims that under its proposed buy-through proposal, there would be a 0.5 mil increase for TEP's residential and commercial customers in the 2017 PPFAC rate if a 60 MW buy-through program is approved.[393] TEP asserts that non-participants would be further impacted negatively by the shift of unrecovered fixed costs though future increases in non-fuel base rates.

TEP argues that under any of the buy-through proposals, TEP and its non-participating

[389] See Ex TEP-30 Jones Dir, Schedule CAJ-3, at sheet 714.
[390] TEP Opening Brief at 42.
[391] *Citing* Arizona Public Service Company Rate Application filed in Docket No. E-01345-16-0036, attachment LRS-06DR (AG-1 Program Evaluation Report).
[392] TEP Opening Brief at 42.
[393] *Id.*; Tr. at 1238-39.

customers face the risk of returning customer loads, and that TEP would not realize any long-term planning benefits since customers would be able to return to TEP's generation service with limited advance notice.[394] TEP asserts that buy-through customer loads are not interruptible and if the buy-through customer's generation service provider fails to deliver power at any time, TEP would still be responsible for serving the buy-through customer's load. TEP claims it would still have to continue to account for these buy-though customers as part of its long- and short-term resource planning requirements.

Moreover, TEP argues that the buy-through proposals are unlawful as the rates violate the fair value requirement of the Arizona Constitution; they are not consistent with the competition statutes and rules; and violate the Management Interference Doctrine. TEP argues that the Arizona Constitution requires the Commission to use fair value to set rates, and even in a competitive industry, the Commission must find and consider fair value in setting rates.[395] TEP states that under the buy-through proposals, the Commission does not set a rate at all (not even maximum or minimum) and the rates are not filed with the Commission. TEP notes that NS's witness, Mr. Bass, stated his company has "prices" not "rates" and that the prices are set without any consideration of fair value.[396] Thus, TEP asserts that when judged under the standard for competitive utilities, the buy-through proposals fail. TEP notes that the proponents of the buy-through program distinguish the buy-though tariff from competitive direct access because the service is ultimately being provided by the utility which contracts with the wholesale provider and then sells the power to the customer.[397] TEP asserts that "[b]ecause the service is ultimately being provided by the utility, the buy-through proposals are subject to the full, traditional rate of return requirements."[398]

TEP argues that even if the electric competition statutes and regulations remain viable after the ruling in *Phelps Dodge*, the buy-through proposals do not meet the requirements of the competition

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[394] TEP Opening Brief at 44.

[395] *Residential Util. Consumer Office v. Arizona Corp. Comm'n*, 240 Ariz. 108, ¶ 13,, 377 P. 3d 305, 309 (2016); *USW Communications, Inc. v. Arizona Corp. Comm'n*, 201 Ariz. 242, 246, ¶ 20, 34 P.3rd 351, 355 (2001); *and see also Phelps Dodge Corp. v. Arizona Elec. Power Co-op, Inc.*, 207 Ariz. 95, 108 ¶ 39, 83 P.3d 573, 586 (App. 2004)., as amended on denial of reconsideration (Mar. 15, 2004)(*Phelps Dodge*).

[396] Tr. at 1125-26.

[397] Tr. at 1017 and 1134.

[398] TEP Opening Brief at 46, *citing RUCO*, 240 Ariz. at ¶ 13, 377 P.3d at 309 (noting that rate or return method with fair value "required… in ratemaking for private, for-profit monopolies.").

scheme.[399] TEP argues that the buy-through program is illegal.[400] TEP notes that AECC relies on A.R.S. §40-202(B) as supporting competition, but TEP asserts this subsection was enacted as part of a framework for electric competition that allows the Commission to control whether competition is allowed, under what terms, and by whom, and that the Act permits competition only by "electricity suppliers" who are regulated public service corporations.[401] TEP argues the buy-through proposals do not comply with the requirements as the buy-through providers do not have electricity supplier certificates, have not accepted public service corporation status, and the buy-through rates would not be tariffed.[402] For example, TEP notes that A.R.S. § 40-207(a) requires that "[a]n electricity supplier shall obtain a certificate from the Commission before offering electricity for sale to retail electric customers in this state"; and A.R.S. § 40-201(14) defines "Electricity supplier" as "a person, whether acting in a principal, agent or other capacity, that is a public service corporation that offers to sell electricity to a retail electric customer in this state." In addition, the Commission's competitive rules require a competitive Electric Service Provider to obtain a Certificate of Convenience and Necessity ("CC&N").[403] TEP asserts that in this case, none of the proposed buy-through providers have valid CC&Ns, nor have any of them indicated they would accept regulated public service corporation status.

TEP distinguishes a buy-through provider from third-party providers of rooftop solar units because rooftop solar providers are selling equipment, not electricity, and the TORS and RCS programs are offered by the regulated public service corporation. TEP argues these utility programs are not precedent for unregulated buy-though providers selling power to customers at untariffed and unregulated prices.[404]

TEP states that the Commission has long acknowledged that each electric utility has the obligation to acquire a prudent mix of generation and the discretion to do so.[405] Thus, TEP states, the Commission found that TEP did not need Commission approval to acquire generation assets. TEP

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[399] TEP Opening Brief at 46.
[400] TEP Reply Brief at 25-26.
[401] A.R.S. §40-201(14); A.R.S. §40-207; A.R.S. §40-208; 30-308
[402] TEP Reply Brief at 25.
[403] A.A.C. R14-2-1602(15) defines "Electric Service Provider" ("ESP") as a company supplying, marketing, or brokering at retail any Competitive Services pursuant to a Certificate of Convenience and Necessity.
[404] TEP Reply Brief at 26.
[405] TEP Opening Brief at 47 *citing* Decision No. 67744 (April 5, 2005) at Attachment A ¶76.

contends that this principle is known as the "Management Interference Doctrine" which holds that the Commission sets rates, but does not manage the utility. TEP asserts that under this doctrine, utility management is responsible for obtaining appropriate generation. TEP argues that because TEP has not agreed to a buy-through program, it would violate the Management Interference Doctrine to require the Company to acquire generation from certain wholesale providers and sell that power to select customers.

AECC has proposed a cap of 60 MW and Wal-Mart proposed a cap of 250 MW for the buy-through program. Further, Wal-Mart proposes to allow customers in the LGS Class to participate and also to aggregate loads. TEP states that the best way to limit the impact of a buy-through on non-participating members is to not approve the program, but if a program is approved, participation should be capped at 30MW, which was based on the APS program, but scaled down to fit TEP.[406] TEP asserts that these larger caps would only increase the harm to customers. In addition, if approved, TEP contends that the minimum load size to participate should be 3 MW, and customers should not be permitted to "aggregate" load to meet the minimum.[407] TEP claims aggregation would broaden the number of possible customers and scope of the resulting problems and would present administrative challenges. TEP also states any program should be limited to the LPS class, as this was the only class mentioned in related portions of the Fortis settlement.

TEP asserts that AECC's claim that the loss of 60 MW of industrial load could be resold into the wholesale market at roughly the same price as TEP's average cost of fuel and purchased power, is unrealistic given the fact that wholesale power prices are projected to be lower than the Company's incremental cost of fuel for a number of periods throughout the year.[408] Furthermore, TEP asserts that a number of the PPFAC eligible costs are fixed and cannot be avoided on a short-term basis, such that a re-dispatch of the Company's generation portfolio would result in a higher average cost of fuel and purchased power as the PPFAC eligible costs would be allocated over fewer kWh sales.[409]

TEP disagrees with the suggestion that the buy-through is a superior economic development

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[406] *Id.* at 48.
[407] TEP Opening Brief at 49-50.
[408] TEP Reply Brief at 24.
[409] *Id.*

tool to the Economic Development Rider ("EDR"). TEP states the EDR is targeted at new business customers or those expanding their operations while the buy-through customers could reduce operations, and still qualify for the program. In addition, TEP states the EDR is designed to attract high load factor customers that will benefit the entire system while the buy-through only benefits the buy-through customers.[410]

a. TEP Response to AECC's Modifications

TEP asserts that AECC's proposal to have the LGS, LPS and high voltage Classes fund the buy-through program places the burden of the program on non-participating customers in those classes.[411] TEP also argues that AECC's witness admits that there would be "winners" and "losers" under his proposal, and that if Staff's or TEP's rate spread is adopted (as opposed to AECC's proposal), the "losers" would lose even more.[412] Moreover, TEP notes that Mr. Higgins conceded that the $7.6 million in funding might not be enough, which would leave other customers on the hook.[413]

With respect to AECC's alternative 5-year opt out modeled after a program in effect for Portland General Electric ("PGE"), under which participating customers continue to pay their regular generation rates for five years, TEP argues the harm to other customer is merely pushed out to the future.[414] TEP claims that under this alternative "one of the lowest cost (at current prices) components of the generation resource portfolio will be preferentially allocated to these select few customers, and the remaining customers will be left with a more expensive resource mix, as well as the responsibility for making up lost fixed generation cost revenues."[415]

TEP asserts that another source of risk is the potential for default by generation service providers who need strong balance sheets because they buy long-term wholesale contracts, but bill customers monthly. TEP contends these providers may encounter financial constraints if the market turns against them, which means that TEP faces counterparty risk that the wholesale provider can't pay while TEP retains responsibility for serving the buy-through load.[416]

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[410] TEP Reply Brief at 24-25.
[411] TEP Opening Brief at 43; Tr. at 1053-54.
[412] Tr. at 1079.
[413] Tr. at 1010-1012.
[414] TEP Opening Brief at 43.
[415] *Id.* at 43-44.
[416] *Id.* at 45.

TEP states that it has to estimate the costs it will incur to schedule and coordinate power deliveries associated with a buy-through. The Company claims that no party has provided an actual estimate of TEP's costs to dispute TEP's estimate, but only rely on APS's management fee. TEP argues that APS's costs may be different than TEP's, and cannot blindly be adopted. Furthermore, TEP notes, APS is alleging that the fee approved for the AG-1 has fallen short of covering the costs of the program.[417]

b. <u>TEP's Response to Wal-Mart</u>

TEP asserts that Wal-Mart's proposed Renewable Generation Service ("RGS") suffers from all the deficiencies of the other buy-through tariff proposals and is not needed. TEP claims that it has a strong commitment to expanding renewable generation, and TEP already provides numerous renewable options to customers who desire additional renewable power, such as: Rider R-5, Bright Tucson Community Solar Program; Rider R-7, Customer Self Directed Renewable Energy Option; and possible contracts with TEP.[418] TEP also notes that under the Wal-Mart proposal, the Renewable Energy Credits ("RECs") would remain with Wal-Mart, and the tariff would not help TEP meet its renewable energy obligations. Furthermore, TEP asserts that the Wal-Mart proposal is entirely conceptual and lacks details or specific tariff sheets.

c. <u>TEP's Response to Freeport</u>

TEP states that it values Freeport as its largest customer and recognizes the important role the Sierrita mine plays in the community, and TEP states that it has worked with Freeport extensively over the years in an attempt to lower the mine's power costs. For example, TEP states that Freeport is exempt from the LFCR and DSM mechanisms and the Company has entered into special contracts with Freeport in the past. TEP states that it developed the 138kV rate especially for Freeport, and has worked to make the revenue allocation more equitable. TEP opposes Freeport's proposed "Franchise Agreement," under which Freeport's subsidiary Morenci Water & Electric ("MWE") would take over

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[417] *Id.* at 48-49.
[418] Tr. at 1066-1067.

electric service to the Sierrita mine.[419] TEP argues that the franchise proposal is neither legal nor wise.[420] TEP states that MWE has no facilities to serve the Sierrita mine, and the arrangement would be strictly a fiction existing only on paper. TEP distinguishes the relationship between the Safford mine and MWE because GCEC voluntarily agreed to the arrangement while TEP does not. In addition, TEP notes that the Safford mine was new load, so the cooperative would not have lost existing revenues or load.

TEP asserts that if the Sierrita load goes away, other customers will have to make up the difference for fixed generation and transmission costs. TEP states that fixed costs are fixed and don't go away just because MWE takes over service of the mine. Even if the franchise agreement were approved, TEP states there are no guaranties that the Sierrita mine won't be shut, as Freeport acknowledges that the biggest factors in determining the level of activity are copper and molybdenum prices.[421]

Furthermore, TEP argues that an "agreement" to which one party does not agree is legally questionable. TEP notes it has a CC&N for the area and is ready and willing to provide service such that there are no grounds to disregard TEP's CC&N.[422] Freeport claims that MWE holds certificates from the Commission and FERC, but TEP assets that MWE's CC&N restricts MWE to serve its designated service area and MWE does not have a competitive electric supplier certificate under A.R.S. §40-207, and is not authorized to sell electricity outside of its designated service area.[423]

Ultimately, TEP states that the franchise agreement brings no certain benefits in terms of preserving jobs or economic activity, and brings certainty that other customers will pay more and should be rejected. TEP states that the Commission has other tools at hand if it believes that Freeport needs assistance, chief among them revenue allocation. TEP states that it would not oppose moving the revenue allocation closer to cost parity. It states this would be a more principled approach than

[419] MWE is a public service corporation. MWE currently provides service to Freeport's Safford mine even though the mine is located in the service territory of Graham County Electric Cooperative, Inc. ("GCEC").
[420] TEP Reply Brief at 26.
[421] Tr. at 1730.
[422] *Application of Trico Elec. Co-op, Inc.*, 92 Ariz. 373, 386, 377 P.2d 309, 319 (1961) ("We hold the Corporation Commission was under a duty to Trico to protect it in the exclusive right to serve electricity in the region where it rendered service, under its certificate."); *James P. Paul Water Co. v Ariz. Corp. Comm'n*, 137 Ariz. 426, 429, 671 P.2d 404, 407 (1983)(Commission may alter or delete CC&N only where holder fails to provide reasonable service at a reasonable price).
[423] TEP Reply Brief at 27.

approving a legally doubtful and economically unsound special deal for Freeport.[424]

2. AECC/Freeport/NS

AECC/Freeport/NS propose three alternative generation service programs which are intended to provide large customers an opportunity to manage their power costs through participating in the competitive generation market.[425] They claim that a competitive market for electric generation is the public policy of the state.[426] They argue their proposals are more likely to spur economic development and sustainability in the local economy than the EDR proposed by TEP. They assert that solar generation customers in TEP's service area already benefit from a "mixed monopoly-competition" model, and that larger customers should be allowed the same opportunity to choose a third-party electric generation service provider.[427]

AECC/Freeport/NS assert that the largest customer classes have a "legitimate interest" in having a meaningful opportunity for "customer choice" and "price competition" in connection with generation service.[428] They argue that allowing the large commercial and industrial customers to purchase power from the competitive market can reduce risk for TEP and its ratepayers because removing load from TEP's IRP process can help delay and/or reduce the acquisition of new generation assets, thus relieving other customers from having to pay the fixed costs associated with an ever-increasing rate base.[429] They also assert that "allowing a company like Freeport to secure generation service on its own can further reduce risk to TEP's other ratepayers in the event the Sierrita mine reduces operations further, leaving TEP's remaining customers to pay for fixed costs to serve the mine that otherwise could be avoided."[430] Further, they state that large customers seeking to limit their carbon footprint could purchase utility-scale renewable energy from the competitive market, which is more cost effective than smaller scale distributed generation systems.

AECC/Freeport/NS's first proposed alternative to Rider-14 was modeled after TEP's proposal,

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[424] *Id.*
[425] AECC/Freeport/NS Opening Brief at 17.
[426] A.R.S. §40-202.B.
[427] Tr. at 815.
[428] AECC/Freeport/NS Opening Brief at 28. The aggregate test year non-coincident peak period demand of the LGS, LPS and 138 kV classes of customers was 575 MW, or 21 percent of the Company's test period non-coincident peak demand of 2,12 MW.
[429] AECC/Freeport/NS Opening Brief at 17; Ex AECC-14 McElrath Surr at 9-10; AECC-11 Higgins Surr at 8-9.
[430] AECC/Freeport/NS Opening Brief at 17.

but expanded in scope to 60 MW and with modifications to pricing, terms to return to standard generation service, and the mechanics of fixed generation cost recovery. According to AECC/Freeport/NS, assuming a non-fuel revenue increase of $81.5 million, it is expected that TEP's revenue deficiency ascribed to the loss of fixed generation revenues under the buy-through would be $7,470,705, which would be apportioned to the classes eligible for the Buy-Through program. By having the eligible classes pay higher rates, they argue that other classes are held harmless. They state that over time, as TEP will be able to account for the Buy-Through in the IRP process, the basis for ascribing any loss of fixed generation revenues to participants would diminish and eventually be eliminated.[431]

AECC/Freeport/NS claim that arguments against their proposal lack merit. First, they assert that the Buy-Through is distinguished from APS' AG-1 program because it contains a funding mechanism to absorb TEP's projected loss of fixed generation revenue, such that non-participants do not have to pay for the cost of the program.[432] Second, they contend that concerns that the losses might exceed $7.5 million are speculative and that the Company could not identify any errors or omissions in Mr. Higgins' calculations. Third, the Company's calculation that the loss of 60 MW of load could increase purchased power and fuel costs by 1.0-1.5 percent, is not well-founded because it is not reasonable to assume that TEP would not be able to sell its freed-up 60 MW into the market at the same price the buy-through customer could obtain the power.[433] Fourth, with AECC/Freeport/NS's cap of 60 MW, even with the $7.5 million of program cost revenue allocation, the eligible customers would still be allocated less revenue than under either TEP's or Staff's proposed allocations.[434] AECC/Freeport/NS note that the participants in this case who might be eligible for the Buy-Through (Freeport, Wal-Mart and Kroger) all indicated that they would be willing to pay slightly higher rates to fund a Buy-Through because of the opportunity for meaningful cost savings.[435] Fifth, they argue the proposed EDR is not as viable or meaningful an economic development tool as the Buy-Through Tariff because the proposed EDR's qualifications are too stringent and its scope too narrow.

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[431] Ex AECC-11 Higgins Surr at 9.
[432] AECC/Freeport/NS Opening Brief at 20; Tr. at 945.
[433] Tr. at 1239 and 2336-2337. AECC/Freeport/NS Opening Brief at 21.
[434] AECC/Freeport/NS Opening Brief at 21.
[435] Tr. at 851, 1726, and 1861.

In response to an expression of interest by Commissioners for options at the Open Meeting on UNSE's rate case, AECC/Freeport/NS developed a second option--the "Five Year Opt-out" Program.[436] They modeled the program after one in effect for PGE. The features of the "five-year opt-out" program as proposed are as follows:

1) The program is open to any customer with an aggregated load of 1,000 kW or greater using facilities that have a maximum billing demand of at least 200 kW over the 12-month period prior to enrollment.
2) Initially, program participation would be capped at 150 MW (comparable to the PGE program scaled for TEP's relative size). Over time, in conjunction with the IRP process, the program cap would be increased to match projected load growth and/or to offset the acquisition of new generation resources.
3) Participating customers would not pay for TEP's unbundled generation charges (inclusive of fixed generation charges, base power supply charges, the PPFAC, the ECA, and the REST Surcharge), but would be required to pay a transition charge for five years. The transition charge would be published prior to a 30-day enrollment period each year. The transition charge would be locked in at the outset and would apply for the duration of the transition period, and at the end of the transition period, participating customers would have no further transition charge obligation to TEP.
4) The transition charge would require the participating customer to pay the difference between the cost of service unbundled generation charges (inclusive of base power supply charges, but exclusive of riders) and the market price of power, where the market price of power and the base power supply charges are projected for five years and shaped to reflect class seasonal and on-peak loads and adjusted (upward) for wheeling costs and line losses.[437]
5) Participating customers would continue to pay TEP's unbundled distribution and transmission charges, both throughout the five-year transition period and after the transition

[436] AECC/Freeport/NS Opening Brief at 25-26.
[437] For purposes of this calculation, the fixed generation charge would be based on the unbundled generation rates in effect at the time of enrollment.

period is concluded.

6) Participating customers located within a TEP-transmission constrained area would also continue to pay TEP's unbundled fixed must-run generation costs, during and after the transition period. Participating customers would be entitled to service from TEP's must-run facilities at cost-based energy rates during periods of transmission congestion.

7) Participating customers could only return to receiving generation service from TEP at cost-based rates following three-year advance notice to TEP.

8) Imbalance charges would apply to participating customers when scheduled power deliveries did not match actual participating customer loads.

AECC/Freeport/NS claim the five-year opt-out proposal benefits TEP and its customers and there is no evidence to support the assumption that reducing short-term power purchases will automatically increase the remaining per customer cost of purchased power. They state that TEP might be able to obtain purchased power at an equivalent or lower per unit cost moving forward depending on the market conditions at the time.[438] Besides, they note, during the first five years of a customer's participation in the program, they would be paying TEP a "transition charge" specifically designed to insure that the customer would pay TEP an amount that covered fixed generation charges deemed attributable to that customer. They argue that the five year transition period would provide TEP with ample opportunity to adjust its IRP process to reflect the reduction in load resulting from the program. They state that because TEP's Preliminary 2016 IRP indicates that TEP will need new generation resources by 2018, if the five-year opt-out is in place by early 2017, TEP will be able to tailor its resource acquisition program to reflect the reduction in its need for additional generation.[439] In addition, because TEP utilizes a mix of purchased power arrangements with a variety of contract lengths, AECC/Freeport/NS assert there is no evidence indicating that TEP's long-term IRP process and its ability to remain flexible in continuing to serve the future requirements of customers would be harmed

[438] AECC/Freeport/NS Reply Brief at 10.
[439] *Id.* at 11. Staff witness Solganick stated that a reduction in load of 30 or 60 MW would probably not affect TEP's decision whether to add a new base load resource; AECC/Freeport/NS state that their proposal for a 150 MW program "similarly would not materially affect such a resource addition decision, particularly since the prospect of a long-term departure from the Company's system as a source of generation service inherent in the program is unlikely to lead to a "rush" of customers electing to do so."

by an opt-out program.[440]

Freeport states that despite TEP's comments about the importance of the Sierrita mine to TEP, its ratepayers and the surrounding community, Freeport has not been presented with a "meaningful solution to *immediately* reduce its power costs at Sierrita."[441] Freeport proposes that TEP enter into a franchise agreement with MWE similar to the franchise agreement between MWE and GCEC approved by the Commission in 2006. Freeport explains that under the GCEC/MWE franchise agreement, MWE provides power directly to Freeport's Safford mine, which is located in GCEC's service territory. Freeport argues that a franchise agreement between MWE and TEP would allow Freeport to utilize its unique position in Arizona to essentially provide the Sierrita mine with generation service through a Commission-regulated affiliate and FERC certified exempt wholesale generator.[442] Freeport states that it is willing to enter into long-term contracts so that TEP can pursue resource planning that does not have to account for the Sierrita load at some future date. That is, Freeport is willing to bear the short- and long-term market risk in the price of generation which would insulate TEP's other customers from paying for fixed generation costs in the event that the Sierrita mine is closed.

AECC/Freeport/NS assert that electric CC&Ns do not confer the exclusive right to provide generation service. They state that in *Phelps Dodge* the Court agreed that the rights conferred by Article 15, Section 7 of the Arizona Constitution protect only a public service corporation's right to construct and operate lines to transmit and distribute electricity and that "[t]he provision does not confer any right to generate the electricity that is ultimately transmitted and sold for public use. Moreover, the provision does not confer any right to exclusively sell electricity."[443] The *Phelps Dodge* court relied on the holding in *City of Mesa*, in which the Arizona Supreme Court held that the City of Mesa could freely compete with the SRP District in a disputed area unless sound reasons required a contrary conclusion.[444]

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[440] AECC/Freeport/NS Reply Brief at 12.
[441] AECC/Freeport/NS Opening Brief at 29.
[442] Tr. at 1713.
[443] *Phelps Dodge*, 207 Ariz. 95, 122 at ¶ 122.
[444] *City of Mesa vs. Salt River Project Improvement & Power Dist.*, 92 Ariz. 91, 99-100, 373 P.2d 722, 728 (1962). AECC/Freeport/NS argue that when read in conjunction with A.R.S. §40-202 (B), the Arizona Supreme Court's decision in *James P. Paul* can be distinguished from the issues in this proceeding as the court did not have to deal with a public policy determination made by the Arizona legislature that the service in question (electric generation service versus water utility service) shall be competitive. AECC/Freeport/NS Reply Brief at 14.

AECC/Freeport/NS assert that their alternative generation service proposals are consistent with sound regulatory policy and in furtherance of the public interest given the record and circumstances of this proceeding. They argue that no Arizona Constitutional provision prohibits the provision of electric generation service to customers in Arizona by a third-party provider, and they contend there is a statutorily declared public policy that a competitive market exist in the sale of electric generation.[445] They argue that their three alternative generation service proposals are legal under Arizona law because:

1. They further the public policy of the state "that a competitive market exist in the sale of electric generation service."
2. They help implement the strategic goal of the Commission to "transition to electric competition as soon as possible."
3. They are similar to programs already approved by the Commission regarding the APS AG-1 tariff and the MWE/GCEC franchise agreement.
4. They are similar to the TORS and RCS programs proposed by TEP in that they provide choice and competitive options to TEP customers in a "mixed monopoly-competition" structure.
5. They are similar to third-party providers of rooftop solar units who also provide choice and competitive options to TEP customers.
6. They provide a solid foundation for expanding customer choice consistent with the Retail Electric Competition Rules, and the customer choice concept underlying those rules; and
7. Under Arizona law electric utilities do not have an exclusive right to provide electric generation service within their CC&N boundaries.[446]

AECC/Freeport/NS argue that TEP and AIC are wrong when they claim the Buy-Through is illegal under Arizona law for allowing the market to set rates and not including a fair value analysis.[447] AECC/Freeport/NS state that their buy-through proposals (which are consistent with the

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[445] AECC/Freeport/NS Opening Brief at 31; A.R.S. §40-202.B.

[446] *City of Mesa v. Salt River Project Agricultural Improvement District*, 52 Ariz. 91, 373 P.2d 722 (1962); *Phelps Dodge Corp. v Arizona Elec. Power Coop., Inc.*, 207 Ariz. 95, 83 P.3d 573 (App. 2004).

[447] AECC/Freeport/NS Reply Brief at 5-9.

administration of APS' AG-1 Tariff) meet Arizona legal requirements that: "(i) sets a range of rates that allow market generators to sell electricity at market rates within a range to a local utility, which generation costs are then passed through to a specific customer, and (ii) is based on a finding and consideration of the fair value of the provider, which in the case of a buy-through tariff, is the local electric utility – not the market generator."[448] AECC/Freeport/NS state that they designed the buy-through to ensure that it comports with the legal requirements set forth in *Phelps Dodge* and other Arizona cases that discuss the fair value determination requirement. They assert that as affirmed in *RUCO v. Arizona Crop. Comm'n*, the Arizona Constitution grants the Commission broad discretion in prescribing just and reasonable classifications to be used and just and reasonable rates.[449]

AECC/Freeport/NS argue that the Commission can legally establish a range of rates that allows market forces to set rates within the approved range. They cite the Appellate Court in *Phelps Dodge*, that found competitive market forces alone to set rates would violate the constitutional requirement that the Commission establish just and reasonable rates, but that "[n]othing in the plain language of Article 15, Section 3 requires the commission to prescribe a single rate rather than a range of rates" and thus, "assuming the Commission establishes a range of rates that is 'just and reasonable', the Commission does not violate Article 15, Section 3 by permitting competitive market forces to set rates within that approved range."[450] They note that APS' AG-1 Tariff includes the minimum and maximum range of charges approved by the Commission and they expect that similar language would be included in the TEP Buy-Through tariff.[451]

In addition, they argue that because TEP would be the provider of the electric service under a buy-through program, the fair value determination requirement is satisfied. Furthermore, because TEP would continue to provide the electric service, they argue the program is not "competition" or "competitive" within the language of the competition statutes or rules (i.e. A.R.S. §40-202(B) and A.A.C. R14-2-1600 *et seq.*).[452] They also argue that TEP is not correct that the Buy-Thorough rates would need to be subject to traditional rate of return requirements because a buy-through program is

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[448] *Id.* at 5.
[449] 240 Ariz. 108 (2016).
[450] *Phelps Dodge* at 207 Ariz. 95, 109, 83 P. 3d 573, 587.
[451] AECC/Freeport/NS Reply Brief at 6.
[452] *Id.* at 7.

not full monopoly service. They assert that under the *US West* decision, using fair value as the basis of calculating a reasonable return on a utility's investment is "not constitutionally required in all cases."[453]

Moreover, they argue that even if the Commission considers service under TEP's territory to be provided under a full monopoly scheme, a range of rates would satisfy the fair value requirement because in this proceeding the Commission will establish TEP's FVRB and the Buy-Through program takes the FVRB and rate of return into consideration. Indeed, they state, the funding mechanism proposed by Mr. Higgins is designed so that TEP will earn its authorized rate of return. They assert that TEP's attempt to liken "fair value" with "rate of return" was rejected by the Arizona Supreme Court in the *RUCO* decision when the Court stated "[a]ccordingly, we reject RUCO's argument that 'fair value' somehow encompasses the determination of the appropriate rate of return."[454]

Furthermore, AECC/Freeport/NS argue that the Buy-Through Programs to not violate the Management Interference Doctrine because they are part of the Commission's ratemaking function.[455] They argue that the Buy-Through Tariff is not an attempt to manage TEP, but rather an attempt to establish just and reasonable rates within the context of a rate proceeding. They note that in *Ariz. Corp. Comm'n v. State ex rel. Woods* ("*Woods*"), the court distinguished between rules designed to control the public service corporation itself and rules that attempt to control rates, and concluded that "even assuming we restrict the Commission's regulatory power to its ratemaking function, we must give deference to the Commission's determination of what regulation is reasonably necessary for effective ratemaking."[456]

3. <u>Wal-Mart</u>

Wal-Mart asserts that an AGS program would not harm other non-AGS customers. Wal-Mart states that the AGS program would replace the Company's own wholesale market purchases with those of the customers participating in AGS, and shift the risk of the Company's wholesale market purchases

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[453] *US West Communications v. Ariz. Corp. Comm'n*, 201 Ariz. 242, 246 ¶ 19 (2001), 34 P.3d at 355 (considering ratemaking in a competitive industry "there is no reason to rigidly link the fair value determination to the establishment of rates.")
[454] *RUCO*, 240 Ariz. at ¶ 14, 377 P.3d at 309.
[455] AECC/Freeport/NS Reply Brief at 9-10.
[456] *Woods*, 171 Ariz. at 307.

from the Company's ratepayers to the AGS customers.[457] Wal-Mart claims that there is ample evidence from APS's experience and from other jurisdictions around the country, that permitting customers to choose their generation service providers is an effective way for customers to manage their electricity needs to better suit their business needs.[458]

Wal-Mart argues that the AGS should not be limited to only the LPS-TOU and 138 kV classes, but should be available to all commercial and industrial classes. Wal-Mart asserts that the Fortis settlement does not prohibit expansion of the program to a broader class of customers.[459] Wal-Mart states that allowing a significant number of customers the opportunity to participate in AGS would attract more generation service providers and create a more robust and vibrant marketplace from which AGS customers could obtain their electric generation service.[460]

In addition, Wal-Mart recommends increasing the cap on the program to 250 MW. Wal-Mart argues that the 30 MW limit is arbitrary, and that a 30 MW cap is too narrow and would severely restrict the number of generation service providers that would be interested in participating in the program.[461] Wal-Mart argues that a 250 MW cap is appropriate because TEP plans to purchase 250 MW to 350 MW of capacity from the wholesale market to cover near term obligations.[462]

Wal-Mart recommends that in order to participate, a customer have a minimum peak demand of 1,000 kW.[463] Wal-Mart contends that this minimum size would ensure that the participant is sufficiently large to be a sophisticated user of electricity and not require any customer protection requirements. Further, Wal-Mart recommends that a customer should be allowed to aggregate utility accounts within its corporate family to meet the peak demand threshold in order to allow participating customers to leverage economies of scale to reduce generation supply costs.

Wal-Mart also argues that the alternative generation program should not be limited to 4 years, because the 4-year limitation eliminates the ability of customers to purchase long-term contracts.[464]

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[457] Wal-Mart Opening Brief at 6; Ex Wal-Mart-4 Hendrix Dir at 9.
[458] Wal-Mart Opening Brief at 7; Ex Wal-Mart-4 Hendrix Dir at 8.
[459] The Fortis settlement specified that a buy-through program be proposed for the LPS class.
[460] Ex Wal-Mart-4 Hendrix Dir at 6.
[461] Ex Wal-Mart-4 Hendrix Dir at 7.
[462] *Id.*
[463] Wal-Mart Opening Brief at 8.
[464] Ex Wal-Mart-4 Hendrix Dir at 8-9.

Wal-Mart believes this factor will be important to those customers who wish to purchase more renewable energy than is currently included in the Company's resource mix, and states such purchases of additional renewable resources would be at the customer's choosing and cost and not harm other TEP customers. Finally, Wal-Mart argues that the Commission should approve a cost-based management fee for the program, but that TEP has not provided any support for its proposed fee of $0.0040 per kWh.[465]

Wal-Mart also proposed a renewable buy-through program called the "Renewable Generation Service" tariff. Under this program TEP commercial and industrial customers with aggregated peak demand of 1,000 kW or greater could voluntarily choose to acquire additional renewable energy. Participating customers would select their preferred renewable provider, with the power to be delivered by TEP.[466]

4. Kroger

Kroger supports either AECC/Freeport/NS's recommendations for a buy-through tariff or the "five-year opt-out" as reasonable means for large customers to access the economic development benefits of the electric power markets.[467] Kroger asserts that the AECC/Freeport/NS proposals balance the interests of the Company and large customers while holding smaller business customers and residential customers harmless.

5. AIC

AIC strongly opposes implementing any of the various buy-through proposals at this time. AIC argues that proponents of the buy-through offerings are wrong when they claim the program will provide customers with choice and will stimulate economic development. In AIC's view, customers will not have a "choice" as to whether they may participate as participation is likely to be a matter of "dumb luck" and winning the lottery given the likelihood that the program will be fully subscribed. In addition, AIC argues that with full subscription at implementation, the program would be a poor

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465 Wal-Mart Opening Brief at 8.

466 Wal-Mart notes that other states have begun to explore ways to allow large customers to contract for renewable energy on a significant scale. For example, Wal-Mart states in Utah, Rocky Mountain Power has a tariff under which a customer contracts for renewable energy with one or more off-site generators, which Rocky Mountain then purchases on behalf of the customers and delivers to one or more customer sites. Alabama Power constructs or acquires renewable generation resources which are paid for through agreements with specific customers. Wal-Mart Opening Brief at 9.

467 Kroger Opening Brief at 4.

attractant for new businesses that would not have an opportunity to participate.

Furthermore, AIC asserts that the alleged benefits of "choice" and "economic sustainability" come at a significant cost to other customers who have no choice not to pay the subsidy of funding the program.[468] AIC argues that "[a] program that subsidizes a few large customers on the backs of others and that cannot guarantee that the Company and its other customers will be shielded from financial harm does not serve the public interest."[469]

AIC asserts that the Commission should pursue cost-justifiable economic development programs that benefit the Company and all customers rather than a few large lucky customers. AIC states that the Buy-Through is a "backdoor" entry into retail competition, which is not allowed in Arizona, and that the Buy-Through suffers from the same legal deficiencies as retail competition, with an energy rate that is set by the market without consideration paid to the fair value of the energy provider's plant in service.

AIC states that AECC and Freeport have been trying to deregulate Arizona's electric industry for more than 20 years, but have failed because the basic tenant of deregulation (also known as "direct access," "restructuring" or "retail competition") that electric rates are set by the market and not the Commission, violates Article 15 of the Arizona Constitution. AIC argues that the Commission has "plenary" power over utility rates, subject to the Constitutional requirement that in setting rates, it must ascertain "the fair value of the property within the state of every public service company doing business therein."[470] AIC asserts that in the *Phelps Dodge* case the Court of Appeals made clear that "Article 15, Section 3 not only empowers the Commission to set just and reasonable rates, it requires the Commission to do so."[471] AIC states that market forces may influence the Commission's determination of what is "just and reasonable," but the Commission cannot "abdicate its constitutional responsibility to set just and reasonable rates by allowing competitive market forces alone to do so."[472] AIC argues that allowing a rate to be set by market forces is illegal in Arizona because (1) it improperly delegates the Commission's duty to the marketplace; and (2) it violates the Constitutional requirement that rates

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[468] Ex AIC-2 Yaquinto Surr at 6.
[469] AIC Opening Brief at 5.
[470] Ariz. Const., Art. 15, Sec. 14.
[471] *Phelps Dodge Corp. v. Arizona Elec. Power Co-op., Inc.*, 207 Ariz. 95, 107 (2004).
[472] *Id.*

include consideration of the fair value of the public service corporation's property.[473] AIC asserts that neither a statute that sets a policy directive, a strategic goal of the Commission, nor the Commission's Competition Rules can trump a constitutional mandate.[474]

AIC asserts that under any of the alternative buy-through proposals in this case, the generation rate would be negotiated between the participating customer and the third party provider, with neither the Commission nor utility having any say, or any consideration of fair value. In addition, AIC asserts that the fact that the energy sale between the third-party provider and the end user is "sleeved" through a utility is not sufficient for the market-based rate to pass constitutional muster. AIC argues such arrangement is a "sham transaction, intended to sidestep the constitutional requirements that the public service corporation providing power to the consumer must obtain a certificate of convenience and necessity from the Commission and charge rates set by the Commission based on the fair value of its property."[475]

AIC argues that the buy-through program in operation at APS suffers from the same legal flaws, but because it was implemented as part of settlement, no party challenged its legality.[476] AIC states that the buy-through program is distinguishable from the MWE and GCU franchise agreement as well as from TEPs TORS and RCS programs, but even if not, the legality of rooftop solar programs has not been tested in court, and their existence does not justify implementing an illegal buy-through program.[477]

AIC asserts that the AECC proposed "five-year opt-out" program is also illegal under Arizona law because the rates paid for generation service would not be set by the Commission or consider fair value.[478] AIC states there is no difference between the opt-out proposal and all-out direct access except for the fact that the market-based rate negotiated between the energy service provider and the opt-out customer is sleeved through the utility.[479] AIC notes that AECC's witness Higgins proposes that the participation cap for the opt-out program should be increased or potentially eliminated over time, so

[473] AIC Opening Brief at 6.
[474] AIC Reply Brief at 2.
[475] AIC Opening Brief at 7.
[476] AIC Reply Brief at 2-3.
[477] *Id.* at 3.
[478] *Id.* at 8.
[479] Tr. at 1018-1020.

that in theory, all of the eligible customers could ultimately choose to take service from the market.[480] AIC asserts that this fact underscores AECC's intent to achieve deregulation indirectly through a buy-through structure what it could not obtain directly.

AIC further argues that the buy-through rate proposals are premature because they are based on the APS AG-1 tariff that is going to be examined in the pending APS rate case. AIC notes that APS claims that the cost of a buy-through outstrips the revenue brought in from the program's capacity reserve and other charges. AIC argues buy-through proponents should argue their cases in the APS proceeding based on vetted data rather than hypothetical assumptions about program costs.[481]

In addition, AIC asserts that TEP's proposed Rate Rider 14 results in a cost shift to the customers who cannot or choose not to participate.[482] Under AECC's funding mechanism, customers in the eligible classes pay higher rates to fund the buy-through program, and AIC notes that while AECC and Freeport may be willing to pay higher rates, for the chance to participate, they cannot speak for other members of the class. Neither is AIC convinced that the proposed $7.5 million funding mechanism is sufficient to cover the program costs. AIC states that if the program costs more than Mr. Higgins predicts, it would result in a revenue deficiency that would need to be collected from other customers, perhaps through the PPFAC, which would result in a cost shift to customers outside the eligible class. AIC argues the proposed modifications to Rate Rider 14 (broadening eligibility and increasing the scale) would enhance the risk of a revenue deficiency and cost shift.[483] AIC does not believe that increasing the program cap and eligibility is appropriate for a pilot program.[484] Furthermore, AIC states that allowing aggregation of loads to meet the program minimum adds a level of complication and would create a broader cost shift. AIC asserts the evidence shows that aggregation would require realignment of fuel purchasing patterns that increase overall fuel costs to other customers by one percent.[485] In addition, AIC states that allowing aggregation would create the new problem of

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[480] Tr. at 1018.
[481] AIC Opening Brief at 10.
[482] *Id.*
[483] AIC Opening Brief at 11-12.
[484] *Id.* at 12. The peak load for TEP's LGS, LPS and 138 kV classes is 575 MW; under Wal-Mart's proposal to increase the program size to 250 MW (and include all non-residential customers) would allow almost half of the Company's non-residential customers to be eligible. Tr. 1855-1856.
[485] Tr. at 2643.

determining the necessary relationship between corporate entities to assess eligibility.

According to AIC, an additional risk associated with the five-year opt-out proposal is that it would only work as a permanent program and not as a limited term pilot.[486] AIC argues it is not reasonable to institute a permanent buy-through prior to vetting the impact of such program in the APS rate case.[487]

Finally, AIC argues that Freeport's proposed "franchise agreement" option is a thinly veiled attempt to force TEP to divest a portion of its service territory, but that the law is clear that the Commission cannot deprive TEP of any part of its certificated service area without a showing that TEP is unable to provide safe, reliable and reasonable service.[488] AIC states that there is no evidence that TEP is unable or unwilling to service the Sierrita mine, and that even Freeport admits that TEP is able to do so and has no quarrel with the adequacy or reliability of TEP's service to the mine.[489]

6. RUCO

RUCO does not oppose the purpose of the proposals, but because it is unclear that the residential class will be held harmless, RUCO does not recommend approving them any of them.[490]

7. Staff

Staff recommends that the Buy-Through proposals be rejected. In general, Staff agrees with TEP and AIC regarding the merits of the proposals, but not with their arguments regarding the legality of the buy-through proposals. Staff states that it does not oppose a buy-though proposal as long as there are no adverse impacts or costs to all other customers.[491] Staff believes that none of the proposals in this case offer the assurance of no added costs or impacts as they choose winners and losers in the business community, and customers not lucky enough to be chosen will end up covering the fixed costs that would have otherwise been covered by the customers selected. Staff clarifies this would include

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[486] Tr. at 946.
[487] AIC Opening Brief at 13.
[488] *Id.*; *See, e.g., James P. Paul Water Co. v. Arizona Corp. Com'n*, 137 Ariz. 426, 430-31 (holding Commission erred in deleting a portion of a utility's service territory without an evidentiary showing that the utility was unable or unwilling to provide service at reasonable rates).
[489] Tr. at 1730-1731.
[490] RUCO Opening Brief at 24. RUCO Reply Brief at 14.
[491] Staff Reply Brief at 7.

impacts on the Company "that could ultimately come back through and impact customers."[492] Staff's witness, Mr. Solganick, opined that there has been ample evidence about the benefits to those customers who would be able to take advantage of the program, but not about the possible impacts on other non-participating customers as a result of the program.

Staff also shares RUCO's concerns that other classes of customers, including the Residential Class, may also be harmed by the buy-through proposals. Staff states that it is important to note that APS's AG-1 tariff was agreed to as part of a global settlement, and that APS, in return for other concessions, agreed not to seek recovery of unmitigated lost fixed generation costs associated with its AG-1 from residential customers.[493] Staff notes that TEP's partial settlement regarding the revenue requirement did not extend to Rider-14, and thus TEP would be entitled to seek recovery of any associated lost fixed generation costs.[494]

Staff is also concerned that buy-through customers may return to TEP service when the energy market becomes more expensive which may impact the customers who were not able to participate in the program.[495] Staff opposes the Company recouping any allegedly lost buy through revenue, including lost incremental revenues, through the LFCR. Staff states that because the Buy-Through tariff would not be available to all customers and the benefits would flow through to only those customers able to utilize the tariff, it is inappropriate to charge all customers for benefits that accrue to a select few.[496]

Staff states that the *Phelps Dodge* court determined that if the Commission establishes a range of rates that is "just and reasonable," the Commission does not violate Article 15, section 3 of the Arizona Constitution by permitting competitive market forces to set specific rates within that approved range.[497] Staff is perplexed that TEP would submit a Buy-Through tariff patterned after the APS tariff, but omit a key feature and then claim that it is unconstitutional because of that absence. Staff does not recommend approving a buy-through tariff in this case for substantive reasons, but asserts that the

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[492] *Id.*
[493] Decision No. 73183 at Ex A, Section 17.2 (Settlement Agreement).
[494] Staff Reply Brief at 7.
[495] Staff Opening Brief at 22-23.
[496] *Id.* at 23.
[497] 207 Ariz. 95, 109; Staff Reply Brief at 8-9.

constitutional problem is easily rectified by incorporating the rate structure from the APS AG-1 tariff.[498]

Staff also asserts that TEP and AIC are incorrect when they argue that the buy-though proposals ignore "fair value" because an important attribute of the proposals in this case is that TEP takes title to the power being procured. Staff states that if an upper and lower limit for the rate is set in this case, then the "fair value" finding in the rate case will satisfy Article 15, section 14 of the Arizona Constitution.[499] Staff asserts further, that even without establishing a range of rates, the buy-through proposals in this case are akin to an adjustor mechanism or a formula rate, both of which are permissible.

However, Staff states that it is not clear what AECC and NS are seeking in this this case when they assert "there are no legal impediments that prohibit the Commission from implementing competition in electric generation, or adopting any of the alternative generation service programs . . ." and their reliance on A.R.S. 40-202(B).[500] Staff asserts that to the extent AECC and NS are advocating for the implementation of competition in generation for public service corporations, it is hard to overlook the ruling in *Phelps Dodge* where the Court specifically indicated that "the Commission cannot carry out its constitutional mandate by allowing competitive market forces to exclusively determine what is just and reasonable."[501] In other words, Staff asserts that true market rates do not pass constitutional muster. However, if AECC and NS are suggesting that the buy-through proposals are legal, Staff agrees as long as the Commission sets a range of rates within which the buy-through rates were required to operate.

Staff argues that the buy-through proposals do not violate the Interference with Management Doctrine.[502] Staff states it is simply not the case that the Commission has historically acknowledged that it is the electric utility's obligation to acquire a prudent mix of generation while the Commission simply evaluates the prudence of these decision after the fact. Staff states that in the exercise of its

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[498] Staff Reply Brief at 9.
[499] *Id.* Thus, the fair value that must be determined is for TEP, not the party from whom TEP would procure the power.
[500] Staff Reply Brief at 10. A.R.S. 40-202 reads in part: "[i]t is the public policy of this state that a competitive market shall exist in the sale of electric generation service."
[501] 207 Ariz. 95, 129, ¶ 153.
[502] Staff Reply Brief at 10-11.

regulatory power, the Commission may interfere with the management of the utility whenever the public interest demands.[503] Further, Staff asserts, the Court of Appeals recognized that the Commission can interfere in the context of resource mix when it held, "[p]rophylactic measures designed to prevent adverse effects on rate payers due to a failure to diversify electrical energy sources fall within the Commission's power 'to lock the barn door before the horse escapes'."[504] If the Buy-Though tariff were designed appropriately, Staff asserts it would be within the Commission's power to approve, just as the Commission has authority to require utilities to diversify their generation portfolios through the REST Rules.[505]

Neither does Staff support Freeport's Franchise Agreement proposal. Staff notes that under the Service Territory Franchise Agreement between MWE and GCEC, GCEC was a willing participant. Furthermore, Staff notes that Mr. McElrath for Freeport acknowledged that TEP is ready, willing and able to service the Sierrita mine, and that that the Sierrita operations are not in danger of shutting down if a Franchise Agreement is not reached with TEP.[506] Staff states that unless the public interest is served by disregarding TEP's CC&N there may not be grounds to compel TEP to enter into a franchise agreement.[507]

8. Analysis and Resolution of Buy-Through Tariff

The benefit of the proposed Buy-Through tariffs to those large customers who would be able to participate is clear. They would be able to take advantage of the current low-cost energy market in order to reduce their operating costs. The potential benefit from possibly avoiding capital investments to service load growth to other ratepayers or shareholders is less direct. There is a potential, but unknown, harm to other ratepayers if the loss of load results in higher costs that would be spread among fewer customers. The Company could suffer lost fixed cost revenues if the tariff pricing is not right.

Unlike the circumstances affecting the AG-1 at APS, where APS agreed to the tariff as part of a settlement, TEP has not agreed to the implementation of a buy-through tariff, and if there are unrecovered lost fixed costs, TEP would be entitled to seek their recovery. The Company presented

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[503] *Southern Pacific Co. v. Arizona Corp. Comm'n*, 98 Ariz. 339, 343 (1965).
[504] *Miller v. Arizona Corp. Comm'n*, 227 Ariz. 21, 29, para 31, 251 P.3d 400, 408 (App.2011).
[505] Staff Reply Brief at 11.
[506] Tr. at 1730 and 1737.
[507] Staff Reply Brief at 11.

testimony that the costs for non-participating customers could be detrimentally impacted by the loss of load. Even if AECC/Freeport/NS are correct that Mr. Higgin's proposed funding mechanism would protect non-eligible rate classes from the costs associated with the Buy-Through, that proposal shifts costs within the eligible rate classes, resulting in winners and losers. At a minimum, the results of APS's experience with the AG-1 should be vetted prior to enacting the proposal for TEP, a smaller utility with fewer ratepayers, to absorb potentially higher costs.

AECC's five-year opt-out program, which could be integrated with the IRP process, presents an interesting alternative.[508] Under this option, TEP would be able to plan for the loss of load in its IRP process over a number of years and thus, the impacts on other customers have a better chance to be protected from adverse rate impacts. This option would need to be designed so that other ratepayer classes would not be harmed by the exit of larger high-load factor customers. The record in this case, does not include a proposed Plan of Administration for the five-year opt-out that would spell out the details for this option, and believe it needs further vetting for us to be able to determine if it would be in the public interest.

Freeport has not alleged facts that would allow the deletion of a portion of TEP's CCNs or force TEP to allow another public service provider to supply the Sierrita mine absent the consent of TEP. Consequently, we do not find that this option would withstand legal scrutiny.

Thus, we concur with Staff that it is not in the public interest to approve any of the proposals before us at this time. We also agree with Staff's legal analysis of the buy-through proposals. As proposed, the buy-through options have TEP acquiring title to the energy of behalf to the buy-through customers, and thus, it is TEP's fair value that needs to be considered. If the buy-through was adopted as part of the rate case, the determination of FVRB would fulfill that requirement. We do not view the buy-though proposals in this case to be forms of competition or direct access. To pass legal muster, however, at a minimum, the buy-through tariffs would need to contain a Commission-approved range of rates.

[508] Tr. at 180 and 374.

We have attempted to address some of the concerns about interclass subsidies by moderating the revenues allocated to the larger classes, although we understand that even so, AECC and Freeport are seeking even greater rate relief with a lower revenue allocation and by being able to take advantage of the currently low market prices for energy. We anticipate that the large commercial and industrial customers will continue to press for the opportunity to lower their energy costs by accessing the competitive energy market. Because Arizona law requires that we take the utility's FVRB into account in setting rates, TEP's next rate case would be the next opportunity for the Commission to consider buy-through-like proposals. By waiting, we will be able to take into account the results of the APS AG-1 experiment, as well as evidence in support of and in opposition to that program. At this time, based on the evidentiary record of this proceeding, we decline to adopt any of the buy-through proposals.

B. Proposed Economic Development Rider ("EDR")

1. TEP

TEP proposed Rider 13, Economic Development Rider, to be similar to the economic development tariff proposed and approved in the UNSE rate case. TEP intends to offer the EDR in order to attract new jobs and economic activity. The EDR will provide a discount to customers that qualify under existing Arizona economic development tax credits.[509] Participating customers could include new customers or customers who expand their existing operations. The proposed discount is higher for customers who "infill" in areas with existing facilities. To participate, customers must have a minimum load factor of 75 percent and a peak demand of at least 3,000 kW to ensure that the new customer does not increase costs for the system.[510]

TEP states that it will absorb any non-fuel costs that are lost as a result of the discount because the "long-term benefits of attracting or retaining large, high load factor customers greatly outweigh the short-term costs."[511] TEP requests Commission approval of the EDR as it did for UNSE.[512]

2. Wal-Mart

Wal-Mart recommends that the Commission approve the EDR.[513]

[509] Ex TEP-21 Dukes Dir at 31-32.
[510] *Id.* at 32; Tr. at 1376 and 1383-1384.
[511] TEP Opening Brief at 41.
[512] TEP Reply Brief at 22; Decision No. 75697 at 89-90.
[513] Wal-Mart Opening Brief at 6; Tr. at 1820.

3. AIC

AIC supports TEP's proposed EDR because it is a benefit to all customers.[514] AIC notes that TEP has sufficient capacity to accommodate the discounts for attracting new business, and the program targets those high peak load customers that can be served most efficiently. In addition, AIC asserts that because TEP is mirroring the State's economic development tax credits for eligibility requirements, the Company is mitigating the administrative costs associated with the program. According to AIC, if the EDR is successful in attracting new customers, all customers will benefit as fixed costs are spread over an increasing number of kWhs or customers.[515]

4. Staff

Staff believes that the proposed EDR has limits and is biased towards existing facilities, and expressed a concerned that combining the proposed EDR with the proposed change to the LFCR may have unintended consequences.[516] Staff's witness Solganick posited that the Company could bill existing customers for generation costs within the LFCR, redirect the generation (energy and capacity) to a new customer attracted by the EDR, and effectively double collect on that load.

Staff states that "[i]n the event that the energy costs are not significant, then Staff would support this limited (volume and time) program to increase employment in TEP's service territory. Staff's support for the program does not extend to any Company request for recoupment of lost incremental revenues absent a supporting record in some future proceeding."[517]

5. Analysis and Resolution of EDR

No party opposed the EDR, and TEP has agreed to absorb any lost non-fuel costs that might result so that other ratepayers are protected. We find that the proposed EDR may provide benefits to the entire TEP system if successful. Any possible double counting of generation costs through the LFCR can be addressed and prevented in the LFCR POA. Thus, as we did in the UNSE rate case, we approve implementation of Rate Rider-13.

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[514] AIC Opening Brief at 15.
[515] *Id.* at 16.
[516] Staff Reply Brief at 6.
[517] Staff Reply Brief at 7.

C. Prepay Metering Program or Prepaid Energy Service

1. TEP

In its Application, TEP proposed a Prepaid Energy Service tariff as an option for customers to manage their energy costs. As proposed, in lieu of receiving and paying a monthly bill, prepay customers will be able to prepay an amount toward their electricity use, will be able to track and receive feedback about their energy usage, costs, and other information to save money and energy. The proposed Tariff provides that customers will be able to access usage and billing information via TEP's website and by calling TEP, and the Company will send alerts to Prepay Customers to provide them with tools to help them manage their energy usage and account balance.[518] TEP's proposed charges, based on TEP's proposed rates are:[519]

Basic Service Charge		$0.67 per day
Energy Charges ($/kWh):		
0-20 kWh per day		$0.063804
Over 20 kWh per day		$0.079600
Power Supply Charge ($/kWh)		
	Summer (May-September)	Winter (October-April)
Base Power	$0.035691 per kWh	$0.032608 per kWh

The Base Power Supply Charge will be subject to an adjustment in accordance with Rider-1 to reflect any increase or decrease in the cost to the Company for energy generated or purchased above or below the base cost of purchased power and fuel.

The Company states the program will give customers greater awareness and control over their energy consumption and bypass certain deposits and fees.[520] The Prepay program is a stand-alone tariff exclusive of certain other pricing options and will be available to all residential customers except those whose service address depends on electrical devices for health-related reasons.

The Company has accepted Staff's recommendation to implement it as a pilot. The Company is also proposing to offer a Lifeline version of the Pre-Pay rates. In this proceeding, TEP requests approval of the tariffs upon which to build the program and then, as a second step, the Company will

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[518] Proposed Tariffs filed November 18, 2015 at page 108

[519] Ex-TEP-32 Jones RJ at CAJ-RJ-1 page 17.

[520] Ex TEP-33 Smith Dir at 6.

seek approval of the Prepay program as an EE measure in the Company's behavioral program through its EE Implementation Plan docket.

TEP asserts that the program would give customers a choice and promote customer conservation as there would be a direct cause and effect structure that enables customers to have more control over their spending habits; provides a billing option that more closely aligns energy consumption and payment to inform choices about energy usage; and customers who prepay for their energy are relieved from posting a deposit because there is less risk of an unpaid arrearage.[521]

TEP states that it agrees with Staff's recommendations to study things such as customer satisfaction, program energy and demand savings, customer interest and other information.[522] It argues that ACAA's concerns should not preclude a pilot program that would collect TEP-specific information.[523]

2. SWEEP

SWEEP states that prepay tariffs can pose significant risks to elderly and limited-income customers because of the immediate electrical service shutoff for nonpayment. In addition, SWEEP states that customers who do not have steady incomes or do not fully understand the consequences of nonpayment can frequently find themselves without electricity. As a result, SWEEP states that adequate consumer protections are essential.[524] SWEEP also asserts that prepay tariffs must incorporate adequate and appropriate energy conservation/management education and usage feedback so that customers increase their awareness of their energy consumption and energy costs, comprehend their usage patterns, and understand the options and tools available to them to reduce energy use and costs.

SWEEP recommends that TEP's prepay efforts be treated as two distinct offerings to customers: (1) an optional prepay tariff; and (2) an enhanced customer education, information, and behavior feedback program to encourage customers to manage and reduce their energy bills and costs. According to SWEEP, any customer choosing to be on the optional prepay tariff should receive the enhanced customer education, information, and feedback services in addition to the appropriate

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[521] TEP Opening Brief at 29.
[522] TEP Reply Brief at 31.
[523] *Id.* at 32.
[524] SWEEP/WRA/ACAA Opening Brief at 20.

consumer protections. Further, SWEEP recommends that the enhanced customer education, information, and feedback program should be made available to all residential customers (not just those on the prepay tariff), so that all customers have the opportunity to benefit.

In addition, SWEEP argues that the prepay tariff and associated rates (e.g. the higher BSC proposed by TEP) should reflect the cost savings to TEP.[525]

3. ACAA

ACAA opposes implementing the prepay program.[526] TEP touts the program as optional, but ACAA claims that in practice, prepaid programs are overwhelmingly used by low-income customers. ACAA claims that because the pre-paid program is more expensive due to an extra $5/month charge, but requires no deposit, customers who could not come up with a deposit might find the prepay option to be favorable in the short-run, but end up with a worse deal in the long-term.[527]ACAA asserts that not only are the prepaid bills higher than standard offer, but participants will often pay a processing fee to pay their bills if they utilize kiosks.[528] In addition, ACAA finds it incomprehensible that TEP would utilize ACE Cash Express as a payment center after the Consumer Financial Protection Bureau has taken action against this company for illegal debt collection tactics. ACAA asks TEP to stop the practice of using payday lenders as payment centers to avoid leading customers to predatory lenders.[529]

ACAA asserts that prepay customers lose many of the customer service features that allow vulnerable customers to maintain service, such as the ability to negotiate a deferred payment plan or budget billing. Because the power would be shut off automatically four hours after a "No Credit Disconnect" notice is sent, ACAA is concerned customers could go without electricity in the summer heat.

In response to TEP's testimony that prepay customers can use a mobile app to pay for and monitor energy usage, ACAA states that using a mobile app requires a checking account, but in Arizona

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[525] *Id.* at 21.
[526] *Id.* at 27.
[527] *Id.* at 28.
[528] ACAA states that in the APS pilot, 63 percent of payments were made at kiosks. Further, reports indicate that prepay customers make an average of 5.5 payments per month which indicates pre-pay customers make more frequent payments than once a month, and often incurring the extra processing charges. *Id.*
[529] SWEEP/WRA/ACAA Opening Brief at 28-29. In its Reply Brief TEP responds to ACAA's comments concerning ACE Cash Express, and states it does not actively promote this company. TEP Reply Brief at 33.

12.8 percent of households do not have access to a checking account, and of the low-income households with smartphones, half have had to cancel or suspend service due to financial constraints. ACAA contends that TEP cannot guarantee that customers will receive notices of a pending disconnection.[530]

ACAA states that if the prepay program must go forward, the preferable option is as a pilot program as recommended by Staff.[531] ACAA believes that to be a meaningful pilot, the program needs to be able to quantify the savings created by participants so that prepay customers can be charged fairly, how low income customers perform compared to non-low-income customers, and whether the program is actually an energy efficiency measure and not just an expedient way to cut off power for inability to pay.[532]

In its Reply Brief, ACAA notes that under Section 11.E.3 of TEP's rules and regulations, customers may make advance payments; thus, prepaid energy service is already available.[533] What is new about the current proposal, according to ACAA, is waiving customer protections regarding written disconnection notices and charging customers more for the service. The Company promotes the Prepay Service as a behavioral energy efficiency option as it creates a greater awareness of energy consumption. But ACAA argues that until it can be found to be an efficient EE program, there is no public interest in having a prepaid rate.[534]

4. Staff

Staff states that it is not opposed to the Prepay program if it is offered as a pilot program for at least 24 months. Staff recommends "there should be no difference in the energy rates charged in the Prepay program and standard Residential rates, especially because the former would be a pilot program and this would reduce customer confusion. Staff recommends that if the Company is able to prove it can accurately determine when a customer moves into the higher kWh usages, the Prepay rates equal the standard Residential rates. If not, the PES should equal the RES first tier energy rate for all kWh usage.[535]

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[530] SWEEP/WRA/ACAA Opening Brief at 30-31.
[531] *Id.* at 31.
[532] *Id.* at 32.
[533] SWEEP/WRA/ACAA Reply Brief at 15.
[534] *Id.* at 16-17.
[535] Staff Opening Brief at 28.

Staff objects to TEP's proposal to include the Prepay program as part of the Company's 2016 EE portfolio. Staff maintains that the program is a billing option, not an EE program as the perceived energy conservation may simply be a result of customers running out of money and being disconnected. Staff notes that TEP has stated that if the Prepay program is not approved as part of its EE portfolio, the data management tools may not be made available, but Staff states that the Company plans to charge a $2.00 fee for those tools and thus, the availability of the tools should not be a basis for including the program in the EE portfolio. Before the Prepay program is made part of the Company's EE programs, Staff believes that TEP should provide data from the pilot program to support the proposition that the program can result in conservation.[536]

In addition, Staff recommends that TEP receive a waiver from providing a written disconnect notice as required under A.A.C. R14-2-211(D) for purposes of the program; that Lifeline customers be allowed to participate; that TEP modify its Prepay Service Agreement in accordance with Staff's recommendations and file it with Staff for analysis, review and approval prior to the implementation of the program; TEP should provide to Staff the third-party evaluation of the Prepay program within 60 days of the completion of the evaluation and should include its recommendation whether the program should be implemented on a permanent basis, continue as a pilot program until the next rate case; the inclusion of a $5 adder to cover the costs of equipment and system implementations for the program; and include Section 20 of the Prepay Service Agreement which addresses the closing of Prepay accounts due to nonpayment.[537]

5. Analysis and Resolution Regarding PrePay Program

We authorize TEP to implement a Prepay Program as a pilot and subject to the modifications recommended by Staff. As SWEEP has noted, the educational materials that are developed as part of the program may prove beneficial to every TEP customer, and we direct TEP to evaluate if they can be expanded to a wider audience, and to discuss such program as part of its next EE Implementation Plan or rate case.[538]

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[536] *Id.* at 29.
[537] Staff Opening Brief at 30.
[538] If such education program is not sufficiently developed by TEP's next EE implementation Plan, the Company should include a status update.

D. Frozen Mobile Home Tariff

1. Tucson Meadows LLC ("TM")

TM owns the Tucson Meadows manufactured home community in Tucson, Arizona. TM purchased Tucson Meadows, a 55 and older age-restricted community, as an existing manufactured home community in 1979. TM has one master meter for electric service and its residents have individual maters on their residences.[539]

TM is billed under TEP's LGS-13 commercial rate schedule. It passes most of the electric bill it receives each month from TEP to its residents based on their respective metered usage.[540] A.R.S. §33-1413.01 controls utility charges in mobile home parks and provides that if a mobile home landlord separately charges tenants for utilities (as does TM) then the landlord cannot charge more than the prevailing basic service single-family rate that the local serving utility or provider charges.[541] TM asserts that the statute has worked a financial hardship for TM because TM is billed at a higher commercial rate under LGS-13 tariff, but is limited to rebilling its residents at the lower residential rate.[542]

TEP has a special rate schedule applicable to mobile home parks that are master-metered – the Mobile Home Park Electric Service – GS-11F. The rates on Schedule GS-11F are lower than the standard rate schedule GS-13. Rate schedule GS-11F is frozen such that no new customers are allowed to join.[543]

TM states that when it acquired Tucson Meadows, it was not aware that there was a choice to make about TEP's rate schedules. TM's witness, Mr. Higgins, could not find "anything indicating that TM has chosen to be on the LGS-13 rate schedule."[544] TEP has not been able to find TM's application

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[539] TM Opening Brief at 1. A master metered customers is one that has a primary meter going into their service areas and then reallocate that energy to sub-meters within their facility.
[540] Ex AECC-8 Higgins Dir at 48.
[541] According to a letter dated September 1, 2016, from Manufactured Housing Communities of Arizona, filed as public comment in this docket, the purpose of the law was to encourage mobile home park tenants to conserve utility services by making tenants responsible for the cost of their utility usage.
[542] TM Opening Brief at 2.
[543] In this case, TEP proposed to change the name of Rate Schedule GS-11F to Mobile Home Park Electric Service (GS-M-F). The new rate schedule includes restrictive language stating that it is "only available to premises historically served on a master metered mobile home park tariff" and that it is "not available to new facilities." Ex AECC-8 Higgins Dir at 48.
[544] Tr. at 975.

for service, and TEP personnel do not know why TM is not charged under Rate Schedule GS-11F.[545]

Because TM is charged for electricity under LGS-13, but can only charge its tenants for power at TEP's residential rates, TM claims that it is unable to recoup the full cost of the service that is billed by TEP, and TM asserts that it is "forced to subsidize the cost of what is truly residential service."[546] TM argues the result is inequitable and never intended by the drafters of A.R.S. §33-1413.01. Moreover, TM argues that there is no public interest served by continuing to freeze the mobile home park rate schedule to existing manufactured home communities.[547]

Mr. Higgins, testified that the LGS-13 Rate Schedules is not well-suited for a customer like TM which has a residential load profile. TM states that while it is a commercial customer, the electricity it purchases is mostly for residential customers. As explained by Mr. Higgins:

> LGS[-13] has a significant demand charge and a 75 percent demand ratchet, which means that . . . the bills these customers receive for demand cannot fall below 75 percent of their demand during the highest month in the year. It should be obvious that such a rate design is not a good fit for a customer that has a residential load profile and has an obligation to resell power at TEP's residential rates.
>
> TEP's mobile home park rate schedule is far more suitable for these customers, but TEP refuses to allow these customers to migrate to it. Because this rate schedule does not allow any so-called new customers to join, including existing master metered mobile home parks that happen to be on other rate schedules.
>
> This situation makes no sense. It does not serve the public interest to force customers to lose money by purchasing power at one rate and reselling it at a lower rate, which is what has been occurring for Tucson Meadows . . . .[548]

TM claims that under existing rates, the financial impact attributable to the prohibition on taking service under GS-11F is more than $21,000 per year, and could be worse due to the 75 percent demand ratchet applicable under the LGS rate.[549] Under TEP's proposed rates in this Rate Case, the difference between TM's average electric charges under TEP's proposed LGS rate and its proposed Mobile Home Park Rate would be $3,460.[550] TM argues that the 75 percent demand ratchet that is part of the LGS-

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[545] Tr. at 2055-2056.
[546] TM Opening Brief at 4.
[547] Tr. at 954-955.
[548] Tr. at 955-956.
[549] TM Opening Brief at 5.
[550] *Id.* at 6; See also TM Reply Brief at 5. Under existing rates, TM pays an average charge of $0.1131 per kWh under Rate Schedule LGS-13, while the average charge under Rate Schedule GS-11F is $0.1072 per kWh. Under TEP's proposed rates, TM would pay an average charge of $0.1215 per kWh under Rate Schedule LGS-13, while the average charge under Rate

13 rate schedules creates significant risk for a mobile home park community. For example, TM argues that a very hot summer could set a new floor billing demand for the remainder of the year which could have a significant impact on TM, which can only pass through residential rates to its residents under A.R.S. §33-1413.01.[551] TM states that the gap between what TM bills its residents and the amount it has paid to TEP under LGS-13 has grown from $40,000-$50,000 per year in 2010 and 2011, to over $120,000 per year in 2015.[552]

TM denies that it is trying to profit from a move to the mobile home park rate, but merely trying to avoid losses. TM states that if the mobile home park rate as proposed by TEP is less than the residential rate proposed by TEP, it is entirely TEP's doing, and if the relationship between the rates should be different, TEP should propose something different, but should not punish TM by denying access to a rate that is specifically designed for the unique circumstances of master-metered mobile home parks.

TM states that TEP will not allow existing mobile home parks to move to rate schedule GS-11F because (1) A.A.C. R14-2-205, which addresses master metering, prevents it; and (2) the rate is frozen preventing the addition of new premises.[553] TM argues, however, that A.A.C. R14-2-205 is inapplicable in the case of TM because the regulation applies to new construction, or expansion of existing permanent residential home parks, while Tucson Meadows is nether "new construction" nor "expansion." TM argues that a frozen tariff can be unfrozen if it serves the public interest to do so, and[554] moreover, the Commission did not freeze the mobile home rate, it froze access to GS-11F, and TEP is proposing a rate increase for GF-11F in this case.[555]

TM argues the solution to its problem is simple and inconveniences no one. It asserts the applicability criteria for rate schedule GS-11F should be amended to remove the restriction on service to new customers, and if rate schedule GS-M-F is adopted, the prohibition on "new facilities" should

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Schedule GS-M-F is $0.1205 per kWh. Both proposed rates are lower than TEP's proposed residential rate. In its December 14, 2016 letter, TM states that the LGS-13 rate schedule is more expensive than the GS-11F rate schedule by $23,456 per year; and under the new TEP-proposed rates, LGS-13 is more expensive than rate Schedule GS-M-F by $3,536 per year.

[551] Tr. at 955.

[552] TM letter in response to Commissioner Tobin docketed December 15, 2016.

[553] Ex TEP-31 Jones Rebuttal at 52.

[554] TM Opening Brief at 7.

[555] TM Reply Brief at 2.

be removed as it is superfluous in light of A.A.C. R14-2-205, and the applicability criteria should be amended to remove any language restricting the rate schedule to premises that have historically been served on the mobile home tariff.

TM argues that TEP's claim that GS-11F is highly subsidized is not supported by evidence or analysis. TM states that Rate Schedule GS-11F is part of the GS rate class which is a subsidy payer, and TEP's CCOSS does not provide any insight into the relative performance of any rate schedule within the rate class.[556] TM argues that if the Commission concludes that the GS-11F rate is being subsidized, the Commission can remedy the issue by approving a different rate that is just and reasonable.

TM asserts that TEP's suggestions that it take over direct service to the mobile home park tenants, or that TM lobby the legislature to charge more for electricity, are clearly more complicated and expensive options than TM's proposed solution. TM also argues that TEP is wrong that the Commission enacted A.A.C. R14-2-205 to prohibit mobile home "master meter" situations like the one facing TM, because R14-2-205 does not apply to TM as it only applies to new construction or an expansion. Besides, TM asserts, A.A.C. R14-2-205 requires mobile home park tenants be individually metered, and TM already individually meters its residents.

TM also requests that the frozen Senior Lifeline and Medical Lifeline discounts for residents of master-mastered mobile home parks be retained.[557] TM notes that initially TEP proposed eliminating the frozen Senior Lifeline and Medical Lifeline discounts for residents of master-metered mobile home parks (including Tucson Meadows) after one year. TEP currently has contracts with 23 master-metered mobile home parks whereby TEP offers Lifeline discounts to qualifying residents.[558] At the hearing, TEP's witness, Mr. Jones, testified that eliminating the frozen Lifeline discounts for residents of master-metered mobile home parks is "not a substantial issue for [TEP]," and "[l]et's consider this particular issue dropped."[559]

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[556] *Id.* at 1.
[557] TM Opening Brief at 3.
[558] Ex TEP-31 Jones Reb at 56.
[559] Tr. at 2094.

2. TEP

According to TEP, Commission approved a special rate schedule for mobile home parks (now known as the Mobile Home Park Tariff, or rate schedule GS-11F), many years ago.[560] The Mobile Home Park Tariff provides that it is available to premises historically served on a master metered mobile home park tariff and is not available to new facilities.[561] It applies 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. It is not available to resale, temporary, standby, or auxiliary service. Access to the special mobile home rate has been frozen since at least the 2007 rate case.[562]

Later, the Commission enacted A.A.C. R14-2-205, which requires that individual mobile homes in new mobile home parks must be metered and served by the utility. Rule 205(A) provides as follows:

> A. Mobile home parks – new construction/expansion
>
> 1. A utility shall refuse service to all new construction or expansion of existing permanent residential mobile home parks unless the construction or expansion is individually metered by the utility. Line expansions and service connections to serve such expansion shall be governed by the line extension and service connection tariff of the appropriate utility.
>
> 2. Permanent residential mobile home parks for the purpose of this rule shall mean mobile home parks where, in the opinion of the utility, the average length of stay for an occupant is a minimum of six months.
>
> 3. For the purpose of this rule, expansion means the acquisition of additional real property for permanent residential spaces in excess of that existing at the effective date of this rule.

TEP asserts that the mobile home park rate is not cost-based, is highly subsidized and should not be unfrozen, and that even TM admits that utilities are expected to follow Commission orders and tariffs.[563] TEP states that TM purchased the business in 1979, many years before the rate was frozen, and thus, had many years to opt into the mobile home park rate. TEP argues it is the customer's

[560] In this proceeding TEP proposes to rename the tariff as GS-M-F.
[561] Ex TEP-30 Jones Dir at Schedule CAJ-C, sheet 202.
[562] TEP's November 29, 2016 Letter. At the hearing Mr. Jones testified the rate was frozen since 2001. *See* Ex TEP-32 Jones RJ at 20.
[563] Tr. at 1066-67.

responsibility to select from the rate schedules available to them.[564]

According to TEP, the biggest problem with the frozen mobile home rate is that it is highly subsidized -- less than the residential rate.[565] TEP argues that TM would be able to resell the power at the residential rate, turning a profit on the power that it did not produce, contrary to the Legislature's intent when it adopted A.R.S. §33-1413.01. In its November 29, 2016 docketed letter, TEP states:

> TEP has no control or no knowledge, regarding the billing and metering practices of MMMHPs, or whether MMMHPs are in compliance with A.R.S. 33-1413.01. For the proposed rates applied to test year consumption data, the GS-11 class is expected to pay 13.5 cents per kWh and the average rate for TM under the proposed LGS rates is expected to be 13.6 cents per kWh. Therefore, TEP does not believe that the GS-11 rate is detrimental or creates any financial disincentives for frozen MMMHP customers, nor does it appear that TM is financially disadvantaged by the LGS rate. [566]

TEP claims that if TM switched to the frozen rate, TEP it would under-recover approximately $20,000 annually, and if all 6 mobile home parks not on the mobile home park rate moved, the aggregate under-recovery could exceed $100,000 annually. TEP states these revenues would need to be collected from other customers.[567]

TEP argues TM has other options including: asking the Legislature to allow it to charge more for reselling electricity, have TEP take over service to the individual mobile homes, or treat the rate differential as a cost of doing business.[568]

3. <u>Analysis and Resolution – Mobile Home Tariff</u>

Neither TEP nor TM know why TM was not on the special Mobile Home Park rate when it was frozen. In its response to Commissioner Tobin's November 10, 2016 letter, docketed on November 29, 2016, TEP identified 128 mobile home park customers on the frozen GS-11 rate and another 6 mobile home park customers (including TM) who take service under either the SGS or LGS rates.

It appears that TM would have qualified for the special Mobile Home Park rate if were not frozen. We find that the record in this proceeding supports allowing TM to take service under rate GS-M-F. We believe this is a simple and fair solution. TEP claims that it would under-recover by $20,000

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[564] TEP Opening Brief at 36; Tr. at 1068.
[565] Tr. at 1069.
[566] MMMHP is "master-metered mobile home park."
[567] *See* TEP letter dated November 29, 2016.
[568] TEP Opening Brief at 36.

annually if TM were allowed to switch rates. This estimate was provided after the hearing and not subject to cross-examination, so it is not possible at this point to judge the accuracy of the estimate as it relates to TM or to any other similarly situated customers considering a switch. TEP also states that TM would not be financially disadvantaged under the LGS rates. However, it is unclear whether TEP is also considering the demand portion of the LGS rate in its claim. TM's analysis indicates that under TEP's proposed rates, the difference in cost to TM (or revenue to TEP) between the LGS-13 and GS-M-F would be only $3,536 per year.[569] If the new rates are as similar as TM and TEP claim, it is not clear why TEP or other ratepayers would be significantly disadvantaged by allowing TM to take service under the Mobile Home Park rate. Although the parties suggested that the frozen mobile home park rate is lower than the residential rate, allegations that it is lower than cost or subsidized were not made until after the hearing. In any event, this is a rate case, where changes to deficient rates are appropriate. If TEP believes that it or other customers are unreasonably disadvantaged by allowing TM to take service under the frozen mobile home park rate, TEP should propose appropriate changes to the rate.[570]

We have no information about the circumstances of the other five identified mobile home parks not on the mobile home park rate. Our determination applies only to TM at this time.

VI. Phase 1 DG Issues

A. Grandfathering DG

1. EFCA

EFCA argues that in the event the Commission adopts rates, tariffs and/or an export rate for DG customers, any customers that submitted an interconnection application prior to the issuance of a final order must be fully grandfathered under the currently existing rate design and NEM tariff.[571] EFCA states this was the policy endorsed in the Sulphur Springs Valley Electric Cooperative rate case, the Recommended Opinion and Order in the Value of DG docket, and the UNSE rate case.[572]

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[569] *See* Attachment TM-1 to TM's December 14, 2016 letter. We note that these calculations were not subject to cross examination.

[570] The Company's claim that it does not know if mobile home parks are complying with A.R.S. 33-1414.01, applies to all mobile home parks, not just TM. We have no reason to believe that TM will violate Arizona law if allowed to switch service.

[571] EFCA Opening Brief at 12.

[572] Decision No. 75697 (UNSE Decision); Decision No. 75788 (November 21, 2016) (SSVEC rate case); Docket No. E-00000J-14-0023 (Value of DG).

EFCA states that TEP proposed that its commercial DG customer not be grandfathered on their current tariff and that they be migrated to a wholly new tariff (i.e. the new SGS, MGS, or LGS class).[573] EFCA argues that this proposal demonstrates a lack of understanding of the purpose of grandfathering. EFCA states "grandfathering" is meant to protect the rights, investments and interests of customers that invested in DG technology and not a policy that allows the Company to protect itself from competition.[574] EFCA states it is unaware of any policy or decision that supports a position that commercial DG customers are not entitled to the same grandfathering protections as residential customers.[575]

EFCA argues that protecting commercial customers' investments in DG is important in order to protect them from impermissible retroactive ratemaking. EFCA asserts the protections extend to being migrated to a wholly new class or subjected to demand ratchets.[576] EFCA states that if commercial DG customers are migrated to the newly-proposed classes and subject to the new rate designs associated with them, these customers could end up paying "significantly" more upon the transition, and the investments they made will be rendered uneconomical and deprived the benefit of their DG systems.

EFCA argues that TEP bears the burden of providing evidence to support any grandfathering proposal deviating from the default policy of full grandfathering on currently existing rates and tariffs.[577] Thus, EFCA asserts that to the extent new commercial rates, classes, rate designs, or tariff are adopted, TEP's commercial DG customers who have submitted an interconnection application prior to the final order in Phase 2 should be afforded the option to be grandfathered on their currently existing rate design and NEM tariff.

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[573] EFCA Opening Brief at 13; Ex TEP-32 Jones RJ at 32. EFCA states that "[s]pecifically, the Company states that it will not extend grandfathering to commercial DG customers because if will allegedly create a 'separate class' that will 'continue to reap the benefits of their net metering rider.'" *See also* EFCA Reply Brief at 21.
[574] EFCA Opening Brief at 13.
[575] *Id.* at 14. See also EFCA Reply Brief at 22. EFCA states that in its Opening Brief, TEP offered no rationale to justify treating SGS customers differently from residential customers when it comes to grandfathering.
[576] EFCA Opening Brief at 15, Tr. at 2105.
[577] EFCA Reply Brief at 22.

2. Vote Solar

Vote Solar supports TEP's updated position on grandfathering solar DG customers from harmful rate design and net metering changes by not making any such changes effective until the date of the Decision modifying the rates.[578] However, Vote Solar states grandfathering issues remain for TEP's existing SGS customers with rooftop solar who are transitioned to the MGS or LGS class and who may face severe rate impacts.[579] Vote Solar argues that to provide full grandfathering, existing SGS solar customers should be grandfathered onto the SGS rate in order to treat these customers fairly as well as to simplify administration.

3. TEP

TEP has taken the position that current SGS DG customers who would be transitioned to the MGS class will be able to remain on two-part transitional MGS rates (should they request so) as of the grandfathering cut-off date (and for the grandfathering period) set by the Commission in Phase 2.[580] TEP also acknowledged that current DG customers will be grandfathered on the existing net metering tariff.[581]

4. Analysis and Resolution Regarding Grandfathering

The Commission explicitly addressed grandfathering in the Value of Solar docket. In Decision No. 75859[582] we stated the following:

> . . . it is important to make clear that for the first utility rate case in which the value of DG methodology we adopt in this proceeding will be used, our default policy is that the new export compensation rate set in that case, as well as any changes to DG-related rate design, should generally apply only to DG systems that file for interconnection to a utility's distribution system after the effective date of the Decision issued in that utility rate case. Unless unique circumstances warrant different results, our default policy for existing DG customers shall be that DG systems that have filed for interconnection to a utility's distribution system before the effective date of the decision issued in that utility rate case should be considered to be fully grandfathered and continue to utilize currently implemented DG-related rate design and net metering for a period of 20 years from the date a DG system files for interconnection. Existing customers with DG systems will be subject to currently-existing rules and regulations impacting DG.

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578 Vote Solar Opening Brief at 18.
579 Vote Solar Reply Brief at 8-9.
580 TEP Reply Brief at 21.
581 *See* January 4, 2017 letter to the Tanque Verde School District.
582 As modified by Decision No. 75932 (January 13, 2017).

> We also take this opportunity to clarify that this default policy is not intended to shield customers with DG systems from generally applicable rate design changes, such as changes for the basic service charge. It is, instead, intended to preserve the expectations that customers with DG systems may have relied upon when they chose to adopt DG technology. . . .[583]

There is no reason to depart from our previous practices or the above statement. Thus, an existing DG customer, or potential DG customer who submits an application for interconnection prior to the effective date of this Decision, would not be subject to any newly imposed charges or rates approved herein.[584] They would be subject to any changes in existing rates (e.g. they would be subject to whatever new BSC or energy charges are approved for their rate class in this proceeding). Further, because we are not addressing proposed changes to the net metering tariff in Phase 1, current DG customers will be able to take service under the existing net metering tariff. A residential or SGS DG customer who submits an interconnection application after the effective date of this Decision, and prior to the effective date of a Phase 2 Order, would be subject to any charges or rates approved in Phase 1, but would not be subject to any future modified tariffs or rate schedules approved in the Phase 2 Order.

Existing commercial DG customers, or those who submit applications for interconnection prior to the effective date of this Decision, whose usage and load profile would qualify them for the new MGS rate or the LGS rate, should have the option of remaining on the transitional MGS two-part rates. They may opt for the MGS or LGS demand rates if they desire.

Because we adopt the recommendation to keep the rate design portion of the case open for 18 months, we may address any unintended consequences resulting from the creation of the new MGS Class as it related to any customers (including DG customers).

B. RPS Credit Option

1. RUCO

RUCO proposes an optional RPS Credit Option that would pay DG customers a rate for their output that is fixed for 20 years at the time each DG system comes online. The rate could apply either to the DG customer's entire output or just to the power exported to the grid. There would be a schedule of declining RPS credits starting close to the current TEP residential retail rate and then decreasing

[583] Decision No 75839 at 156.

[584] They would be subject to any changes in existing charges or rates (e.g. they would not be subject to a new DG meter charge if approved in this proceeding, but would be subject to any change in the BSC or energy rates).

according to a pre-set series of steps based on installed DG MW capacity.[585] RUCO explains that the capacity tranche was formulated to create an average blended rate across all tranches around 7.7 cents/kWh which conforms to RUCO's long-term breakeven analysis, and that the capacity targets are close to yearly REST compliance targets.[586] Mr. Huber testified he set the decline rate roughly equal to historical system cost declines, choosing a yearly 7 percent decline rate.[587] Mr. Huber explains the final rate would be the Market Cost Comparable Conventional Generation ("MCCCG") rate plus any adder the Commission deems appropriate in a post-RPS compliance environment to recognize the local renewable energy attributes.

RUCO proposed the following tranches of capacity and price per tranche:

Capacity per Tranche (MWs)	kWh Price per Tranche
6.0	$0.110
6.8	$0.100
7.7	$0.090
8.5	$0.085
9.4	$0.080
10.3	$0.075
11.1	$0.070
12.0	$0.065
12.8	$0.060

RUCO argues that the Commission should approve RUCO's recommended RPS Credit option in Phase 1 of this proceeding because it provides an option for solar customers, is a mechanism that provides certainty for solar customers, and was approved in the recent UNSE rate case.[588] RUCO states that it designed the RPS Credit to be identical to the RPS Credit that was approved in the UNSE rate case. The difference between RUCO's proposal in this case and in the UNSE rate case, is that TEP needs 85 MW of additional DG to become REST compliant.[589] RUCO clarifies that only new DG

[585] Ex RUCO-10 Huber Dir at 41; Ex RUCO-11 Huber Surr at 9.
[586] Ex RUCO-11 Huber Surr at 9.
[587] *Id.* at 10
[588] RUCO Opening Brief at 4-8.
[589] Ex RUCO-5 at 41.

generation that exchanges RECs will count toward the tranches.[590] RUCO argued that with the Value of DG docket still not complete, the RPS Credit option provides certainty to solar customers.

In response to EFCA's criticisms, RUCO states it intentionally designed the RPS Credit option to be independent of the Value of DG docket and the rate was developed using the avoided cost method as a guide in an effort to provide certainty to solar customers.[591] RUCO is adamant that the "Value of Solar" is not the cornerstone of the option.

Both EFCA and Vote Solar have argued that RUCO's proposed capacity tranches are too narrow and would fill too quickly. RUCO asserts that this claim is founded upon a misunderstanding of which installations would count toward the tranche. RUCO clarifies that only installations that opt for the RPS Credit will count toward tranche capacity, and that it is impossible to know how fast the tranches will fill given the optional nature of the rate.[592] EFCA also asserts that the RPS rate is not levelized over 20 years and represents a substantial reduction in compensation for DG customers.[593] RUCO argues that EFCA's claim is based on an assumption retail rates will continue to increase and comparing the RPS Credit option to a 20-year fixed yearly payment is irrelevant as the compensation rate was designed as a completely separate compensation structure and to pay less than the full retail rate.[594]

Vote Solar suggested that the final tranche compensation rate should be 7.9 ¢/kWh rather than the MCCCG rates (currently 2.5¢) to avoid undervaluing solar.[595] RUCO counters that the MCCCG rate may look low now, but the market sets the rate, and not long ago the MCCCG was 5 ¢/ kWh.[596] RUCO asserts that it will be a number of years before the tranches are full, and speculation over what the rate may be is unimportant because: (1) the rate is optional; (2) the Commission can modify the

[590] RUCO Opening Brief at 7. In response to perceived criticism about changing positions, RUCO is adamant that it has always been the intent that the tranches only applied to the DG capacity installed under the RPS Credit Option. See Tr. at 1601-1603.
[591] RUCO Reply Brief at 2-3.
[592] *Id.* at 3-4.
[593] EFCA Opening Brief at 18.
[594] RUCO Reply Brief at 6.
[595] Vote Solar Brief at 10-11.
[596] RUCO Reply Brief at 5.

tranches for public policy reasons; and (3) as a utility becomes REST compliant, the non-DG rate payers should not be asked to subsidize additional solar generation.[597]

RUCO also asserts that if the tranches are modified to include all solar capacity, the intent of the mechanism would be lost because the intent of the option is to provide the utility with RECs, and to include capacity for which no RECs are exchanged, does nothing to bring the utility closer to REST compliance.[598]

Further, RUCO asserts that Vote Solar's proposal to base the tranches on yearly installation rates links the tranches to solar sales, rather than to REST capacity goals. RUCO argues that because Vote Solar's proposed 28 MW tranche size would meet the REST MW compliance target after only 3 tranches, the remaining tranches would overpay for rooftop solar exports which does nothing for REST compliance.[599] RUCO states that its intent is to help the utility become REST compliant in the most economical way, staying consistent with REST requirements.[600]

2. EFCA

EFCA urges that RUCO's RPS Credit Option be deferred to Phase 2 of this proceeding because the plan is flawed and incomplete as currently designed.[601] EFCA notes that when the Commission approved the RPS Credit Option in the UNSE rate case, it did so "on the fly" at Open Meeting, and provided that the option would be offered for a short-term, temporary basis until the parties and Commission can "address the long-term feasibility" of the option in Phase 2 of the UNSE rate case.[602]

EFCA notes that RUCO has suggested that the average RPS Credit across all of the steps or tranches of capacity should be "the long-term value of solar,"[603] and that RUCO witness Huber explained the export rate is not set up to pay the value of solar, but rather less than the value of solar.[604] Thus, EFCA contends the rate is based on one person's opinion as to the value of solar and clearly the rate was not designed to ensure consistent application of the results of the Value of Solar docket.[605]

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597 RUCO Reply Brief at 6.
598 *Id.*
599 *Id.* at 7.
600 *Id.*
601 EFCA Opening Brief at 15.
602 *Id.* at 16.
603 Ex RUCO-11 Huber Surr at 9.
604 Tr. at 1552.
605 EFCA Opening Brief at 16-17.

EFCA argues that because the RPS Credit Option is dependent on the outcome of the Value of Solar Docket, it should be considered in Phase 2 of this proceeding to ensure its accuracy.

EFCA asserts that the RPS Credit Option's tranches must be reviewed in Phase 2 since they are based on the Value of Solar and tied to the economics of DG.[606] EFCA states that it is clear that the proposed tranches are too narrow and directly affect the economics of DG, and Mr. Huber did not know or analyze when each tranche would be filled.[607] EFCA states that based on the rate of installation in TEP's service territory in 2015, the first five tranches would be fully subscribed within a single year.[608] Thus, EFCA asserts the tranches are too narrow and the respective rates for each tranche do not comport with principles of gradualism, causing the DG market to drop quickly to the lowest economic tranche, exhaust the limited available capacity, and "go bust."[609]

EFCA also argues that the RPS Credit option rate is not levelized and represents a substantial reduction in compensation for DG customers.[610] EFCA explains that under net metering today, bill savings escalate over time as retail rates increase.[611]

EFCA warns that "premature" adoption of the RPS Credit option based on the currently proposed tranches will create confusion and add administrative expense for TEP as it is essentially creating a pilot program that TEP will have to implement and maintain over a 20-year period.[612] To be consistent with the UNSE rate Order, EFCA states that any adoption of the RPS Credit Option in Phase 1 of this case would also be re-evaluated in Phase 2, and if the program is altered in Phase 2, TEP will have grandfathering issues associated with any DG customers who elect the RPS Credit option prior to revision in Phase 2. Furthermore, EFCA asserts that implementing the RPS Credit option would create a substantial effort including customer education about the new option, website development to provide public daily tracking of the tranches, and the re-design of billing systems.

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[606] *Id.* at 17.
[607] Tr. at 1528.
[608] Tr. at 2107.
[609] EFCA Opening Brief at 17; Ex EFCA-12 Beach Supp at 8.
[610] EFCA Opening Brief at 18.
[611] For example, according to EFCA, if TEP's current residential rate of 11 cents per kWh grows at 2.5 percent per year, the 20-year levelized retail rate (at a 7.26 percent discount rate- TEP's weighted average cost of capital) is 13.3 cents per kWh which represents the actual 20-year levelized bill savings under NEM.
[612] EFCA Opening Brief at 18.

EFCA questions the benefit and wisdom of incurring these nontrivial costs for a program that might be supplanted within a few months.

If the Commission is inclined to implement the RPS Credit Options in Phase 1, EFCA proposes several modifications including:

(1) The rate should be close enough to compensation under net metering to be viewed as a reasonable option for new solar customers, consistent with the rate design principle of gradualism. EFCA recommends commencing the RPS Credit Option rate at 95 percent of the current 20-year levelized TEP rate, or 12.6 cents per kWh.

(2) The credit would then be reduced by 5 percent in each successive tier; and

(3) The size of each tranche would be 28 MW, as recommended by Vote Solar, so that the tranches last about a year.

3. Vote Solar

Vote Solar argues that the Commission should not approve RUCO's RPS Credit option. Vote Solar states that there are significant policy benefits to an optional rate with a structure similar to the RPS Credit option, as allowing customers to lock-in a compensation rate for 20 years would provide price stability and avoid grandfathering issues. If properly designed, Vote Solar believes that the RPS Credit option could provide customer choice and predictability to the solar market. However, Vote Solar argues that to achieve these benefits, RUCO's proposed RPS Credit option must be redesigned. According to Vote Solar, the structural issues include: (1) determining the appropriate compensation rate that solar customers should ultimately receive for their generation; and (2) determining the pace at which compensation will be reduced to achieve that rate. Vote Solar argues that RUCO's proposal is seriously flawed because the final compensation rate of 2.5¢ would be too low and the compensation rate would decrease unpredictably. Vote Solar recommends that if the Commission approves an RPS Credit option before Phase 2, it should increase the final compensation rate to at least 7.9¢/kWh, increase each tranche size to 28 MW to reflect current annual installation rates, and clarify that all new rooftop solar capacity will count toward the tranche capacity limits.[613]

[613] Vote Solar Opening Brief at 11.

Vote Solar argues that the final compensation rate under RUCO's proposal of 2.5¢/kWh is unreasonable and would severely undervalue solar. According to Vote Solar, the 2.5¢/kWh is far less than RUCO's 7.9¢/kWh value of solar estimate and less than TEP's proposed compensation rate of 5.84 ¢/kWh based on utility-scale prices.[614]

Vote Solar criticizes the 2.5 ¢/kWh for not being based on any metric tied to the value of solar, or any other "principled basis related to solar generation or solar policy."[615] Even if the compensation rates are flexible, Vote Solar argues that the Commission should not approve RUCO's proposal simply because there is a chance that a more appropriate final compensation rate may be selected in the future. If the Commission wishes to approve the RPS Credit option in Phase 1, Vote Solar asserts that it should set an appropriate final compensation rate now.[616]

Vote Solar states that the primary strength of the RPS Credit Option is that it would gradually decrease solar compensation if the Commission decides it is no longer appropriate to compensate solar customers at retail rates.[617] Vote Solar states that if that occurs, the compensation for solar production should reflect the value of the energy exported to the grid, but Vote Solar states the last four tranches in RUCO's proposal would compensate solar customers below RUCO's own conservative value of solar. Thus, Vote Solar argues that the compensation rates under RUCO's proposal would not send appropriate or accurate price signals to customers. If the Commission approves the RPS Credit option in Phase 1 of this proceeding, Vote Solar asserts that the final compensation rate should be no lower than 7.9¢/kWh, which is RUCO's "conservative value of solar estimate." [618] Vote Solar claims that this change would result in an economically optimal outcome. In any event, Vote Solar states that the Commission should revisit the final compensation rate in Phase 2.

In addition to adjusting the rates, Vote Solar recommends expanding the size of the tranches. Vote Solar believes that the tranche size is a critical policy decision that will determine how gradually or quickly the compensation rate will decline. During the course of the hearing, there was some confusion about whether all rooftop installations would count toward the tranche capacity, or only

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[614] Ex RUCO-10 Huber Dir at 37-38; Tr. at 1517-1518; Ex TEP-4 Hutchens Dir at 25.
[615] Vote Solar Opening Brief at 12-13.
[616] *Id.* at 13.
[617] *Id.* at 14.
[618] *Id.*

those installations that opted for the RPS Credit option. RUCO explained that only solar installed under the RPS Credit option would count toward the tranche capacity limits.[619] Even with the clarification, which means the tranches will fill less quickly than if all installations counted, Vote Solar asserts that RUCO's proposal remains problematic because it would be impossible to predict how quickly the tranches would fill. Vote Solar argues this is a critical policy choice and the Commission should not approve RUCO's proposal due to the uncertainty.

If the Commission approves the RPS Credit option in Phase 1, Vote Solar recommends that it modify the tranches so that all solar installations, not just those opting for the RPS Credit Option, count toward the tranche capacity limits. Vote Solar asserts that this would eliminate much of the uncertainty of RUCO's proposal as current installation rates could be used to project how quickly each tranche will fill.[620] In addition, Vote Solar recommends adopting four tranches with 28 MW of capacity per tranche. According to Vote Solar, based on current installation rates, each 28 MW tranche would fill in approximately one year.[621] Vote Solar argues that by resizing the tranches so that each tranche is designed to remain in effect for approximately a year, would promote gradualism and avoid unnecessary customer confusion regarding the applicable compensation rate.

Vote Solar recommends the following tranches and compensation for the RPS Credit Option:

Tranche Size	RPS Credit Rate
28 MW	11¢/kWh
28 MW	10¢/kWh
28 MW	9¢/kWh
28 MW	7.9¢/kWh

Vote Solar recommends that the ultimate compensation rate schedule be developed based on the following principles:

(1) Compensation rates should be gradual, beginning at or near retail rates and changing slowly

[619] Tr. at 1523-25 & 2227.
[620] Vote Solar believes that RUCO's clarification that only solar installed under the RPS Credit option would count toward tranche capacity helps minimize concerns the tranches would fill too quickly, but it creates the concern of tranches filling unpredictably. Vote Solar Reply Brief at 8.
[621] Ex Vote Solar-5 Kobor Surr at 12.

over time.

(2) The final compensation rate should be informed by the Value of Solar proceeding, as implemented in Phase 2.

(3) Once the final compensation rate is achieved, the methodology for determining that rate should be periodically reapplied to inform future rate modifications.[622]

Vote Solar argues that the proposal has received substantial scrutiny in this proceeding and the Commission should not feel obligated to approve the exact proposal approved for UNSE.

4. Koch

Mr. Koch does not believe that there are any benefits to adopting the RPS Credit option during Phase 1 of this proceeding. Rather, he argues, the option should be considered during Phase 2.[623] He argues that if the option is adopted during Phase 1, the tranches should not have declining values because this runs the risk of dropping the credit option below what the market will bear and "stalling or killing" the solar industry with no action by the Commission. He argues that an annual review by the Commission would be sufficient to set the rate in a way that sustains the market while providing the best value to the ratepayers. He suggests that the initial rate start at a value less than the current compensation rate for net metered customers. Mr. Koch testified that a rate of $0.095 or $0.10 per kWh would be appropriate at this time.

5. Staff

Staff does not oppose the RPS Credit because it is optional, and "[u]ntil the Commission decides what, if any changes should be made to net metering, the RPS Credit Option provides an additional option to existing net metering customers."[624]

6. Analysis and Resolution of RPS Credit Option

The concept of RUCO's RPS Credit option offers a way to provide certainty to the solar DG market. Because the intent is to provide RECs to TEP for REST compliance, RUCO's proposal is that only capacity of customers who agree to exchange RECs and who opt-in should count toward the tranches is appropriate (as opposed to all solar rooftop capacity as proposed by Vote Solar).

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[622] Vote Solar Opening Brief at 17.
[623] Koch Opening Brief at 2-3.
[624] Staff Opening Brief at 37.

The concept of the RPS Credit that applies adjusted compensation rates based on a changing "value of solar" could be adopted to apply to all installations. Presumably this option will be discussed further in Phase 2 following the conclusion of the Value of DG docket. If the RPS Credit option is modified in Phase 2, theoretically, there will be two different RPS Credit options that would be administered in parallel after the conclusion of Phase 2 – the version adopted in Phase 1 (applicable to those DG customers who opt in prior to Phase 2), and the version adopted in Phase 2. TEP did not discuss the RPS Credit option in its briefs. We can presume that the Company's failure to object indicates that it does not believe that any resultant costs of administering the program will not be substantial, and that it is neutral on its adoption.

We find no harm created by adopting RUCO's proposal in Phase 1, and see some benefit to DG customers who desire to opt-in sooner rather than later in order to obtain some certainty in their compensation rate. Customer experience with the option may help inform any needed modifications in Phase 2 to improve the tariff. Our disinclination to adopt Vote Solar's proposed modifications to the interim tariff should not be read as disapproval of the proposals. The option will be examined again in Phase 2.

C. Meter Charge for DG Customers

1. TEP

TEP requests that the Commission approve an additional meter charge for new DG customers to cover the cost of a second meter that is required to serve them. TEP proposed a charge of $8.62 for residential DG customers and $9.13 for SGS customers based on its marginal cost study. TEP asserts that it is important to keep in mind that the charge would only apply to new solar DG, and the relevant cost should be what a new meter costs today. Thus, TEP argues that using the marginal cost study is appropriate rather than historical embedded costs because these are new customers who are imposing new incremental costs.[625] TEP contends that its proposed charges are conservative because they are for traditional meters rather than the more expensive bidirectional meters required for DG customers.

TEP argues that the second production meter for DG customers is necessary because the REST

[625] Ex TEP-32 Jones RJ at 24.

Rules require the Company to record PV production data for its customers and that complying with this obligation is a cost of providing service.[626] TEP states that the LFCR POA also requires production data for the LFCR calculations.[627] TEP asserts that while inverters may provide production data, they do not have billing quality accuracy, and produce data in various formats that are inconsistent with TEP's billing system.[628]

Moreover, TEP notes that the Commission recently approved an additional meter charge for new DG customers in the UNSE Rate Order. In Decision No. 75697 the Commission stated:

> The meter-related costs for the second meter required by DG customers is not being paid directly by DG customers and is currently being passed on to non-DG customers. It is appropriate for each DG customer to bear the cost of that second meter.

TEP argues that DG customers should bear the costs of the second meter because the meter costs would not be incurred but for the choice of DG customers to install DG systems.[629]

TEP argues that the DG production meters provide benefits to DG customers who can use them to monitor their systems. However, TEP asserts that in any event, costs should be assigned to cost causers and the test under this regulatory principle is not who benefits, but who causes the costs. TEP argues the second meters would not be installed except for the customer installing the solar system, and thus, that customer should bear the cost and it should not be shifted to other customers under the current practice.[630]

Mr. Koch opined that the charge should only be approved if a customer can opt out of the second meter, but TEP states because the second meter is required to comply with Commission rules and requirements, there can be no opting out.[631]

2. <u>RUCO</u>

RUCO proposed a $6 meter fee for new DG net metering customers. RUCO based its meter fee on the Company's marginal cost study (attributing $3.10 for the cost of the meter and $2.90 for

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[626] TEP Opening Brief at 39-40; A.A.C. R14-2-1812 (B)(1); Tr. at 883-884.
[627] Tr. at 2345 and 1473.
[628] TEP Opening Brief at 40; Tr. at 2347.
[629] TEP Opening Brief at 40.
[630] TEP Reply Brief at 22.
[631] *Id.*.

administrative costs).[632] RUCO claims that the estimate is conservative because it does not take into account the incremental additional cost of an upgraded bidirectional meter unique to solar customers.[633] RUCO notes that the Commission adopted a meter fee for new DG customers in Phase 1 of the UNSE rate case, and believes that there is no reason to depart from the decision in that case.[634]

RUCO argues that this issue must be placed in context and considered in the light of the facts and circumstances of each particular case. RUCO notes that in the UNSE case, the meter charge was the result of a last minute proposal by UNSE at Open Meeting, and UNSE was not recommending a charge that covered all of its embedded costs, but was looking to establish a placeholder, or proxy for the production meter cost.[635] RUCO asserts that the meter cost was not thoroughly vetted in the UNSE case, and consequently a very conservative number was approved. RUCO argues that although embedded costs were used in determining the UNSE fee, the best data to determine new meter costs is a marginal cost study. RUCO asserts further that in the present case, we know the actual hard costs (administrative, meter reading, hardware) of the second meter from the marginal cost study, and it is appropriate to include them in the approved charge. RUCO argues that Phase 1 is intended "not to calculate the total embedded costs but to determine a proxy that moves the Company forward in starting to recover meter costs."[636] RUCO argues that its proposed $6 meter fee is fair and a reasonable proxy toward collecting the meter fees associated with rooftop solar. RUCO claims that at $6 interim meter cost is not unreasonable given that the capital cost alone for a bi-directional meter is $216 and installed cost of a production meter is $71, such that a $6 a month and it would take almost 4 years to off the combined install cost for these two meters (not including carrying costs).[637] RUCO claims that Mr. Huber's proposed administrative costs associated with installation of the second meter were only intended to be estimates, with the precise number to be determined in Phase 2.[638]

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[632] Tr. at 1545.

[633] RCUO Opening Brief at 9.

[634] *Id. citing* Decision No. 75689 at 118; see also RUCO Reply Brief at 7-8. RUCO argues the meter fee is not an additional rate, but rather an additional charge on the rate for the class.

[635] RUCO Opening Brief at 10, citing Transcript of the 08/11/2016 Open Meeting at 523, attached to RUCO Opening Brief as Exhibit B. The Commission approved a meter charge for new DG of $1.58 for UNSE.

[636] RUCO Opening Brief at 11-12. *See also* RUCO Reply Brief at 8-9.

[637] RUCO Reply Brief at 9.

[638] RUCO Reply Brief at 10.

3. Vote Solar

Vote Solar urges the Commission not to require new DG solar customers to pay a second meter fee. Vote Solar notes that TEP's proposed meter fee ($8.62 for Residential customers and $9.13 per month for SGS customers) is over five times greater than the $1.58 per month approved for UNSE.[639] Vote Solar asserts that the Commission should defer the solar meter proposals until Phase 2 of this proceeding.

Pointing out that the Commission has deferred "issues related to changes in net metering and rate design for new DG customers" until Phase 2, Vote Solar argues that the proposed solar meter fee raises solar rate design issues because it implements a new fixed charge that would increase solar customers' monthly bills and alter the economics of rooftop solar, and because it would impact TEP's fixed cost recovery from new solar customers. Vote Solar argues that approving a solar meter fee now would prevent the Commission from holistically and comprehensively deciding solar rate design issues in Phase 2.[640] Vote Solar contends that there is no critical distinction between "rate" and "charge" with respect to the proposed meter fee, and in any case, determining the appropriate "charge" that certain customers will pay is a "paradigmatic" rate design decision.[641]

Vote Solar also contends that there are critical differences between the UNSE rate case where a meter fee was approved in Phase 1, and the current proceeding which warrant deferring the meter fee proposals until Phase 2, including: (1) the meter fee proposals in this case are three to five times greater than the UNSE fee and would have a more significant impact on the rates of new solar customers; (2) the UNSE fee was approved after a full evidentiary hearing on solar rate design and net metering issues, but here the evidentiary hearing on these issues will not occur until Phase 2; and (3) the timing of the TEP and UNSE cases is substantially different as the time between Phases 1 and 2 in the TEP matter will likely be substantially less than in the UNSE case. Vote Solar asserts that deferring the meter fee proposals until Phase 2 would minimally burden TEP because the Commission may issue a Phase 2 decision within months of the Phase 1 Decision.[642]

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[639] Similarly, Vote Solar notes that RUCO's proposed fee of $6 is three times the UNSE approved charge.
[640] Vote Solar Opening Brief at 3.
[641] *Id.* at 4.
[642] Vote Solar Opening Brief at 4-5.

Vote Solar claims TEP's and RUCO's meter fee proposals unreasonably inflate the incremental metering costs for solar customers because they inaccurately calculate the incremental capital costs associated with the meter and overestimate the incremental administrative costs.[643] Both TEP and RUCO set the capital cost component of the additional meter at $3.10 per month. TEP has stated that the $3.10 is not the actual cost of either a bidirectional meter or a production meter, but is a proxy figure that reflects the average cost of a standard meter.[644] TEP claims that the $3.10 is consistent with the UNSE meter methodology, and TEP and RUCO believe it is a "first step" toward adequate cost recovery because it is less than the actual capital costs for a bidirectional meter.[645] Vote Solar asserts that the capital component of these meter fee proposals is flawed because it is not consistent with that UNSE meter fee which reflected the per-unit embedded costs for a standard meter, while the current proposals reflect the per-unit marginal costs for a standard meter. Vote Solar states that had TEP and RUCO used the embedded cost of a standard meter, the charge would be $1.64 per month, and if the Commission wishes to implement a fee that is consistent with the UNSE Decision, the entire meter fee for new residential solar customers would be $1.64 per month.[646]

In addition, Vote Solar asserts that the $3.10 proxy charge is actually not the marginal cost of a standard meter, but the marginal cost of a bidirectional meter.[647] Vote Solar argues that because solar customers already pay for the costs of a standard meter through the basic service charge, TEP's and RUCO's proposals are not merely conservative "first steps" toward recovering capital costs as claimed.

Vote Solar states that the second component of the proposed meter fee is a charge to recover the incremental administrative costs attributable to solar customers who participate in net metering.[648] Vote Solar claims both proposals overestimate administrative costs and are not supported by the record. Vote Solar states that TEP and RUCO did not calculate the actual incremental administrative costs TEP

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[643] Id. at 5-8. When a residential or small commercial customer installs rooftop solar, TEP must replace the customer's "AMR-based" meter with a bidirectional meter that measures the solar customer's consumption and exports to the grid. Ex TEP-32 Jones RJ at 24; RUCO-11 Huber Surr at 13. TEP also installs a production meter so that it can track its compliance with the REST Rules.

[644] Tr. at 1976-77 and 1979.

[645] Tr. at 1979, Ex TEP-32 Jones RJ at 24; Ex RUCO-11 Huber Surr at 13.

[646] *See* Final Schedules at G-6-1, and note that the labels for lines 26 and 28 are switched and the unit cost of "meter reading" should be $0.32, and the unit cost of the "meters" should be $1.64.

[647] Vote Solar Opening Brief at 6-7; Tr. at 1982-1987; Ex Vote Solar -2.

[648] Vote Solar Opening Brief at 7. TEP sets the administrative cost component at $5.52 per month and RUCO sets it a $2.90 per month. Tr. at 1981 and 1545.

incurs when it installs a bidirectional meter, but merely assume that the administrative costs for solar customers are double the administrative costs for a non-solar customer.[649] Vote Solar asserts that it is illogical and counterintuitive that every type of administrative expense doubles when TEP installs a second meter for a solar customer. Vote Solar charges that neither TEP nor RUCO offer a plausible explanation why advertising expenses, salaries and other administrative costs double when a customer installs solar. Vote Solar states TEP has offered no evidence of the additional administrative costs it incurs when a customer signs up for solar and that the Company has stated that it "does not currently track these costs at this level of detail at this time."[650] Vote Solar cites A.A.C. R14-2-2305 which provides that TEP "shall have the burden of proof" on any new or additional charge for solar customers.

Vote Solar asserts that TEP's discussion about the costs of a "second meter" is fundamentally flawed because it doesn't reflect the actual costs that TEP incurs when a customer installs rooftop solar. Vote Solar notes that when a customer installs rooftop solar. TEP replaces the customer's standard "AMR-based" meter with a bidirectional meter and a production meter. Vote Solar states that TEP's proposal does not recover the actual incremental cost of either the bidirectional meter or the production meter, but would recover the costs of a generic second meter.[651] The proposed costs are for more than the actual incremental metering costs of the bidirectional meter, and Vote Solar argues that proxy charges and generic assumptions should not be allowed to inflate the fee.[652] In addition, Vote Solar argues that marginal costs should not be used to set the fee, as rates are set based on embedded costs, and because the fee would be unavoidable, marginal costs are not necessary to send a price signal.[653]

Vote Solar asserts that a meter fee should be limited to the actual incremental capital and labor costs for a bidirectional meter. Vote Solar states that a bidirectional meter benefits solar customers because it allows them to export energy to the grid, while a production meter solely benefits TEP

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[649] Vote Solar Opening Brief at 7.The Administrative Costs TEP includes in its proposed fee are those included in FERC accounts 902-905, 908-910 and 920-935, which include Meter Reading (Account 902), Customer Records and Collections (Account 903), Advertising (Account 909), and Salaries (Account 920). RUCO's proposal is the same except that it would include half of the administrative costs for Account 903 (Customer Records and Collections).

[650] Ex Vote Solar-3 TEP Resp. to VS D.R. 11.03.

[651] Vote Solar Reply Brief at 3.

[652] Vote Solar notes that TEP and RUCO claim that their meter fees are conservative because they reflect the costs of a traditional meter, but that at the hearing, it was shown that the marginal cost study actually reflects the cost of a bidirectional meter. Vote Solar Reply Brief at 5; Tr. at 1987.

[653] Vote Solar Reply Brief at 3.

because it allows the Company to track its REST compliance.[654] According to Vote Solar witness, Ms. Kobor, the total capital and labor incremental cost to install a bidirectional meter is $142.95 for a residential customer, and $23.74 for a small commercial customer. Thus, Vote Solar argues any meter fee approved in this case should reflect these costs, and new solar customers should have the option of either paying these one-time incremental costs up-front, or on a monthly basis. Ms. Kobor calculates the monthly fee for residential customers should be $2.05, and $0.34 per month for a small commercial customer.[655] Moreover, Vote Solar recommends that if the Commission approves a meter fee, it should revisit the issue in Phase 2, and should direct TEP to determine the incremental embedded capital costs for a bidirectional meter and update the meter fee accordingly at that time.

4. <u>EFCA</u>

EFCA states that the meter fee that TEP is proposing for new DG customers is approximately 5 times the meter fee approved in the recent UNSE rate case. EFAC asserts that the fee is intended to cover the costs of the production meter, which EFCA claims provides no benefit to the DG customer and is installed solely for the benefit of the utility. EFCA asserts that REST compliance is a community benefit because the increased use of renewable energy benefits not just the DG customers, but TEP, its ratepayers, and all of Arizona.[656] As such, EFCA argues that the proposed meter fees should not be permitted because not only would the fees discourage the development of distributed generation, they would inappropriately impose new costs on the group of customers who provide the benefits of renewable energy.[657] Thus, EFCA argues that the fee should be borne by all customers and not just DG customers.[658]

EFCA notes that the production meter is used to track compliance with REST requirements, and the calculation of the LFCR. EFCA asserts that compliance with the REST serves everyone, not only DG customers. EFCA argues that DG customers have no duty to install DG whereas the Company has a duty to have DG installed, and so the production meter is clearly for the benefit of the utility and not needed by the DG customer. EFCA asserts that TEP's attempts to justify the need for the meter as

[654] See Tr. at 882-884 and 2144.
[655] Vote Solar Opening Brief at 10; Tr. at 2117-2118; Ex Vote Solar-6.
[656] EFCA Reply Brief at 13.
[657] EFCA Reply Brief at 13.
[658] *Id.* at 14; EFCA Opening Brief at 10.

a possible way to manage the distribution system are speculative. In addition, EFCA asserts using a marginal cost study to support the cost of the meters is inappropriate.[659]

EFCA asserts the fees would make a significant impact on the economics of DG, and cites Mr. Koch's testimony that the extra fees could add a year to the payback period of a system.[660] EFAC argues that the additional fixed charges harm the value of solar and make TEP's customers less likely to adopt it.

5. Koch

Mr. Koch argues that unless solar customers can opt out of the requirement to install a solar meter, they should not be charged a solar meter fee. He asserts that the solar customers do not need the second meter for their own operations or maintenance for a piece of equipment that only benefits the utility in meeting the REST requirements. He states that customers who wish to sell their RECs to the utility or some other party could pay for the solar meter through the proceeds of the REC sale.[661] He asserts that currently, solar customers already pay for the labor costs for the installation of these meters, while TEP pays for the equipment and the ongoing meter reading services.

6. Analysis and Resolution of DG Meter Fee.

TEP and RUCO take the position that DG customers (not all ratepayers) should pay for the costs of the production meter that is installed with a rooftop system. TEP and RUCO rely on a marginal cost study to support the cost of the meter at $3.10 per month, and they both add costs for the administrative expenses, with TEP proposing a total meter fee of $8.62 for residential DG customers and $9.12 for small commercial DG customers, and RUCO proposing a $6 meter fee for residential customers. Both TEP and RUCO claim the fee is justified because the Company would not incur the expense of the production meter but for the customer's choice to install solar, and costs should be assigned to the cost-causer—in this case the individual ratepayer who installs solar. They also argue that the fee is consistent with the decision in the UNSE rate case to impose a meter fee of $1.58 for new residential DG customers.[662]

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[659] EFCA Reply Brief at 13.
[660] Tr. at 1756. Mr. Koch's business installs DG systems.
[661] Koch Opening Brief at 3. Mr. Koch states that because most solar customers today are not selling their RECs to TEP or others, they do not have a need or financial incentive to install such a meter.
[662] Staff did not take a position on the imposition of a meter charge in Phase 1 of this proceeding.

We agree that an interim meter fee for new DG customers is appropriate until we can review and approve a holistic rate design for DG customers in Phase 2. However, we also agree with Vote Solar's position that the fee should not be based on the cost of the production meter, but on the incremental cost of the bidirectional meter that is necessary for DG customers to receive credit for their systems' production and to receive compensation for their excess production. The production meter supports REST compliance (and LFCR calculations). The REST Rules are for the benefit of all ratepayers, the Company, and society in general, and the cost of REST compliance should not be imposed only on the group of customers who contribute to meeting renewable goals. The bidirectional meters, however, do benefit the DG customers who receive compensation for their production, and it is appropriate on an interim basis that new DG customers are responsible for the additional costs of serving them.

The evidence supports Ms. Kobor's calculation that the total incremental capital and labor cost to install a bidirectional meter is $142.95 for a residential customer and $23.74 for a small commercial customer, and that the appropriate monthly fee should be $2.05 for residential and $0.35 for small commercial. New DG customers subject to this charge should have the option of a one-time upfront fee or the monthly charge.

If we were to use the same methodology to set the DG meter charge in this case as we did in the UNSE case, the monthly charge would be $1.64 for residential customers. The record on the appropriate fee was more developed in this case than in the UNSE proceeding, and justifies a refinement of the methodology used in the earlier proceeding. We note that in both cases, the fee adopted in Phase 1 will be further evaluated in Phase 2, and may be further refined.

VII. Other Issues

A. Revisions to TEP Rules and Regulations

1. TEP

TEP has proposed revisions to its Rules and Regulations Tariff to: (1) modernize the Rules and Regulations; (2) update provisions to meet current operational needs; and (3) bring them closer to the Rules and Regulations of its sister company, UNSE, that were approved in Decision No. 75697 on August 18, 2016. During the course of this proceeding, both Staff and ACAA raised issues with the proposed revisions. TEP believes that it has resolved all of Staff's concerns, but some ACAA concerns remain.[663]

TEP does not agree with ACAA's request that Lifeline customers be held harmless from the modifications regarding deposits in Subsection 3.B.3.

TEP's proposed Section 3.B.3 applies to Establishment of Service and provides as follows:[664]

> Residential Customers – the Company may require a residential Customer to establish or reestablish a deposit if the Customer becomes delinquent in the payment of two (2) bills or has been disconnected from service during the last twelve (12) months.
>
> Deposits or other instruments of credit will automatically expire or be refunded or credited to the Customer's account after twelve (12) consecutive months of service following full payment of deposit during which time the Customer has not been delinquent two (2) times or has not been disconnected for non-payment, unless the Customer has filed bankruptcy in the last twelve (12) months.

TEP's revisions reduce the number of delinquencies from three to two before a deposit may be requested.

The Company believes that equitable treatment among customers regarding deposits is appropriate. TEP states that it takes significant efforts to provide workable solutions for customers who are facing challenges paying bills or deposits. TEP also does not agree with ACAA's request to excuse customers who file for bankruptcy from providing a deposit. TEP states that a deposit on a post-petition account is an appropriate assurance of payment under 11 U.S.C. § 366. Finally, TEP asserts that Subsection 3.B.3 is consistent with the Rules and Regulations or other Arizona utilities, and UNSE's Rules and Regulations that were recently approved.

2. ACAA

ACAA proposed that low-income customers be "held harmless" from TEP's proposed rule change that would allow the Company to require more frequent deposits and from the proposal to have deposits "expire under more stringent circumstances."[665] ACAA asserts that little analysis was

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[663] ACAA states that is pleased with TEP's commitment to streamline the weatherization program, to maintain the deferred payment plan length at 6 months, to maintain the Lifeline rates for master metered customers and to modify the termination notice to include customer assistance information. Although recognizing that the Commission cannot order the shareholders to increase their support for bill assistance programs, ACAA requests the Company to increase its annual bill assistance contribution from $150,000 to $200,000. SWEEP/WRA/ACAA Opening Brief at 24-25.

[664] Ex TEP-33 Smith Dir at DAS-1, sheet 903-1.

[665] SWEEP/WRA/ACAA Opening Brief at 25.

provided to justify the changes, and although the Company's witness, Ms. Smith, testified that bad debt was "creeping up," she could not quantify the change and was unable to quantify the impact that increasing deposits collected from low-income customers would have on the bad debt.[666]

3. Analysis and Resolution of Revisions to Rules and Regulations

Ms. Smith testified that "[i]f/when certain factors make it challenging for a customer to pay a bill and/or deposit, it is brought to the Company's attention and every attempt is made to provide a workable solution. These solutions may include referrals to assistance agencies, payment arrangements, or simply granting extra time. The Company has a long-standing history of working directly with individual customers to help them successfully meet their payment obligations. In 2015, the Company granted 287,178 payment extensions to customers based on stated need."[667]

We agree that there is some benefit to keeping the rules and regulations of service conditions applicable to residential customers uniform and that the two month delinquency threshold is reasonable. It is also reasonable to provide consistency with the rules and regulations approved for UNSE. However, we continue to expect that the Company work with its customers on a case-by-case basis and tailor remedies to the circumstances. Consequently, we approve Section 3.B.3 as proposed.

B. Lost Fixed Cost Recovery Mechanism

1. TEP

TEP proposes to modify the LFCR to include recovery of fixed generation costs and 50 percent of non-generation demand costs. TEP also wants to increase the cap on the LFCR from 1 percent to 2 percent. TEP argues that the changes are necessary in order for the LFCR to achieve its purpose of recovering the lost fixed cost revenues caused by complying with Commission mandates, and that without the changes, 60 percent of TEP's lost fixed cost revenues due to EE and DG programs remain unrecovered.[668]

TEP notes that electric utilities have considerable fixed costs associated with owning and

[666] *Id.* ACAA notes that the average residential bill for TEP is $105.57, which means the average deposit should not exceed $211.14. In the Federal Reserve's "report on the Economic Well-Being of U.S. Households in 2015" 55 percent of respondents said they would not be able to cover an emergency expense greater than $200. ACAA states that if households are not able to come up with this payment, service won't be restored, and utility shut-offs have shown to cause forced moves and at least one study shows that unaffordable utility bills were a second leading cause of homelessness for families.

[667] Ex TEP-34 Smith Rub at 8-9.

[668] TEP Opening Brief at 13-14; TEP Reply Brief at 8.

operating generation plants, transmission lines, local distribution facilities and other assets vital to providing service, and that the vast majority (80 percent) of these costs are being recovered in volumetric per kWh charges.[669] TEP states that since 2012, cumulative sales reductions attributable to EE and DG reached nearly 1,000,000 MWh, which equates to about 11 percent of TEP's test year sales; and in addition, residential use per customer has fallen about 7.5 percent from 2011 to the end of the test year.[670] TEP asserts that the combination of a heavy reliance on kWh charges to recover fixed costs and falling kWh sales results in persistent and significant unrecovered fixed costs.

In TEP's last rate case, the Commission approved the current LFCR in order to provide a mechanism to recover some of the lost fixed cost revenues caused by Commission-mandated EE and DG programs. Approved as part of a settlement, the LFCR excluded generation costs and 50 percent of non-generation demand charges. TEP claims that at the time the LFCR was initially approved, the levels of lost revenues resulting from EE and DG were considerably less than today and the LFCR was a "tolerable" compromise in settlement.[671] TEP asserts that the prior rate case settlement agreement did not contemplate that the LFCR structure was permanent or precedential such that it could not be modified to address changes in circumstances to reflect the Commission's Decoupling Policy.[672]

TEP states that the lost fixed cost recovery problem is growing worse as Commission-mandated EE and DG expand. In 2014, the restrictions in the LFCR meant that the LFCR failed to recover $13 million in lost fixed cost revenues due to EE and DG. In 2015, the under-recovery grew to $19.6 million, and TEP expects it to grow to $25.7 million in 2016.[673] TEP's treasurer Mr. Grant, testified that with falling kWh sales, "it is becoming increasingly important from a credit rating perspective" to ensure that more of TEP's fixed costs are actually recovered.[674]

TEP asserts that the Commission has recognized that its regulatory mandates concerning EE have caused sales erosion and adversely impact fixed cost recovery, and has endorsed revenue

[669] TEP Opening Brief at 13, *citing* Ex TEP-4 Hutchens Dir at 13.
[670] Ex TEP-4 Hutchens Dir at 7.
[671] TEP Opening Brief at 13.
[672] TEP Opening Brief at 14, citing Ex TEP-42 Final ACC Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures.
[673] Ex TEP-32 Jones RJ at 8, Table 1.
[674] Ex TEP-9 Grant Rebuttal at 4.

decoupling mechanisms as the way to address the problem.[675] TEP states that not only did the Commission endorse some form of decoupling mechanism to address the financial disincentives to enable aggressive use of DSM programs and the achievement of EE standards in its Policy Statement on the issue, but in its last rate case, the Commission recognized that in approving EE/DSM programs, the Commission must provide a mechanism to allow TEP to recover the fixed costs associated with the lost kWh sales from EE/DSM programs.[676] TEP argues that the reasoning of the Commission's Policy Statement and prior rate case applies in the current situation, as costs currently excluded from the LFCR are fixed costs that are going unrecovered due to Commission mandates.

RUCO has argued that fixed generation costs should be excluded from the LFCR because TEP has the opportunity to sell excess generation in the marketplace. TEP states that generation costs constitute a large portion of the fixed costs incurred to meet customer need and are primarily recovered in volumetric charges, and argues that there is no reasonable basis to exclude generation costs from the LFCR. TEP claims the argument against including generation costs are misplaced because the LFCR is limited to fixed costs, and TEP is not proposing to include purchased power in the LFCR, as these costs are not fixed and flow through the PPFAC.[677] TEP explains that the fixed generation costs that it proposes to include are those associated with TEP-owned power plants. TEP states power plants have long lives and cannot simply be adjusted out of existence.

Staff has stated that "generation is fungible" and not affected by EE or DG if the energy is delivered to a new customer, an existing customer using more energy, or sold off system.[678] TEP asserts that any scenario based on increasing retail sales is unrealistic. TEP asserts that the IRP that suggests sales would increase, was based on growth in mining loads, which are far from certain, but must be considered for TEP to stand ready to provide service when needed.[679] Further, TEP states it has been clear that the Company only seeks to recover quantifiable lost fixed costs associated with the Commission mandated DG and EE, and has agreed to include an adjustment that would account for

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675 TEP Opening Brief at 14-15; Ex TEP-42.
676 Ex TEP-42; Decision No. 73912 (June 27, 2013) at 64 and 65.
677 TEP Reply Brief at 10.
678 Staff Brief at 13.
679 TEP Reply Brief at 10-11; Tr. at 1244.

any increased retail sales in the LFCR if the fixed generation costs are included.[680]

TEP states that short-term generation sales are accounted for in the PPFAC and long-term generation sales are accounted for in the jurisdictional allocation. TEP claims it is simply not the case that it can make up the lost generation costs with wholesale sales because long-term sales are hard to come by in the current market and priced "well below TEP's fully embedded cost of generation" such that they will not cover the fixed costs.[681] In addition, TEP states some generation is "fixed must run" or "reliability must run" ("RMR") that is needed to maintain the integrity of the distribution system and cannot be resold. TEP argues the must run units benefit all customers and their fixed costs should be fully recovered.[682]

TEP asserts that the 50 percent limit on recovering demand charges is arbitrary and particularly problematic because demand charges are designed to only recover fixed costs. In response to RUCO's claim that demand charges will remain constant or change slower than a straight volumetric rate,[683] TEP states that if billed demand remained constant, there would be no problem, but claims that assumption is not well-founded as only fixed costs are assigned to demand charges, and reductions in billing demand directly reduces fixed cost recovery.[684]

In response to the AECC position that LGS customers should be exempted from the LFCR, TEP asserts that these customers benefit from EE and DG programs, and TEP recovers a large portion of fixed costs to serve them through volumetric rates, therefore it is appropriate to keep the LGS customers in the LFCR.[685]

SWEEP opposes expanding the LFCR, but has suggested that approving a full decoupling mechanism that goes beyond the LFCR would better align the interests of the Company and its ratepayers in achieving EE and DG goals. TEP responds that a full decoupling mechanism is an interesting proposal that merits further consideration in a future rate case, but that that SWEEP has not made a detailed proposal in this docket for consideration. TEP notes that full decoupling would go

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680 Ex TEP-32 Jones RJ at 6.
681 Ex TEP-5 Grant Rebuttal at 5; Ex TEP-39 Robey RJ at 10.
682 TEP Opening Brief at 17.
683 RUCO Opening Brief at 21.
684 TEP Reply Brief at 12.
685 TEP Reply Brief at 12.

beyond the Company's own proposal, and TEP argues that it is reasonable to try to fix the problem within the existing LFCR before adopting an entirely new approach.[686]

In addition to including additional lost fixed charge revenues, TEP seeks to increase the LFCR's annual year-over-year incremental cap to 2 percent to allow for more timely recovery of approved costs and ensure that current customers pay their current costs. TEP also requests that the LFCR fixed charge option be eliminated because no customers have opted for it. In addition, TEP requests that the separate EE and DG LFCR charges be combined into a single LFCR charge to simplify customer bills. Finally, TEP has proposed submitting a revised Plan of Administration ("POA") for the LFCR to reflect the modifications approved by the Commission, within 60 days of the Decision in this matter.

2. <u>RUCO</u>

RUCO opposes the Company's proposed modifications to the LFCR. RUCO states the proposal to include generation costs is not new, and has been rejected by the Commission in the past. RUCO claims the impact of the proposal would more than double the effect of the LFCR.[687] RUCO states that the Company's purchased power program has significant flexibility, which allows it to adjust its purchases to match its short-term needs. RUCO asserts that purchased power is fungible and not affected if energy is delivered to a new or existing customer or sold off system, such that the Company has many opportunities to adjust its energy supply.

RUCO asserts that the Company's request to modify the LFCR appears to follow from a mistaken belief that fixed costs must be collected through fixed charges.[688] RUCO states that the Commission has not declared that the Company is entitled to collect all of the lost fixed costs due to EE and DG from the LFCR, and recently rejected a similar request in the UNSE rate case. RUCO reiterates that the LFCR was never intended to be a full decoupler. Moreover, RUCO argues that including generation in the LFCR will reduce TEP's financial risk as more costs will be recovered as a fixed charge, which risk-reduction is not reflected in the ROE to the benefit of the Company and detriment of rate payers.[689]

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[686] TEP Opening Brief at 19; TEP Reply Brief at 12.
[687] RUCO Opening Brief at 20.
[688] RUCO Reply Brief at 12.
[689] RUCO Reply Brief at 13.

RUCO also cites Staff's witness Solganick's claim that the proposed change to include generation in the LFCR in combination with the proposed Economic Development Rates could have significant unintended consequence if the Company could bill existing customers for generation costs within the LFCR and redirect the generation to a new customer attracted by the proposed economic development rates and thus double collect on that load.[690]

RUCO also opposes the proposal to increase the distribution demand component from 50 to 100 percent. RUCO acknowledges that distribution costs are not as fungible as generation costs, and that some distribution assets cannot serve customers within the short term, such that a reduction in per-customer sales can result in a shortfall in revenues to cover these costs. However, RUCO notes that some of the Company's rate schedules collect distribution costs through demand charges which will remain constant or change more slowly than a straight volumetric rate, and thus argues that collecting 100 percent of the distribution demand component is not appropriate.[691]

RUCO asserts that increasing the LFCR cap is not necessary if the Commission does not approve the changes to the LFCR. Finally, RUCO believes that applying a single line item on the bill for EE and DG costs eliminates transparency which would be contrary to the public interest.

3. AECC/Freeport/NS

AECC/Freeport/NS assert that TEP's proposed changes to the LFCR should be rejected. They state that when the Commission approved the LFCR as part of the settlement in the last case, the limitation on its scope was an important aspect for parties like AECC to agree to its implementation.

AECC/Freeport/NS have concerns about whether the LFCR is even needed since a significant part of TEP's lost fixed cost recovery issues can be addressed through proper rate design. AECC/Freeport/NS also argue that LGS customers should be exempt from the LFCR going forward because the premise of the LFCR is to insulate TEP from the loss of fixed-cost recovery associated with conservation or EE efforts, and TEP can mitigate the loss thorough a greater proportion of fixed cost recovery included in the customer charge and demand charges.[692] AECC/Freeport/NS assert this is especially true for members of the LGS class where TEP is proposing to increase the customer charge

[690] RUCO Opening Brief t 20; Ex Staff-10 Solganick Dir at 55.
[691] RUCO Opening Brief t 21.
[692] AECC/Freeport/NS Opening Brief at 15.

to $1,000 per month. According to AECC/Freeport/NS, excluding the LGS Class from the LFCR would not shift costs to other classes because only costs attributed to the participating classes should be recovered.

4. <u>AIC</u>

AIC supports the Company's proposal to allow for the recovery of all of the fixed costs attributable to the distribution and generation components of retail sales through the LFCR.[693] AIC states that according to the evidence in this proceeding, the LFCR only recovers 41 percent of the lost fixed costs associated with energy efficiency measures and rooftop solar, and resulted in a revenue loss of $13 million in 2015.[694] AIC asserts that without enhancing the LFCR or establishing another means to collect the lost revenues, TEP will be required to file a constant string of rate cases. AIC claims such an outcome would almost certainly impair TEP's attractiveness as an investment and could undermine its credit rating in the future.

5. <u>SWEEP</u>

SWEEP does not support any of TEP's proposed changes to the LFCR mechanism and urges the Commission to use "great caution" in reviewing the Company's proposal and should not approve any changes that increase the amount of lost fixed-cost revenue recovery from customers compared to the existing mechanism.[695]

SWEEP proposed full revenue decoupling as an effective approach to address the issues TEP raised with that LFCR. According to SWEEP, full revenue decoupling with a symmetrical adjustment of over- or under- recovered revenues would address the issues and reduce the risk for TEP and its customers.[696]

6. <u>EFCA</u>

EFCA argues that the LFCR should not be modified as requested because the LFCR was meant to mitigate, not dilute or counteract the DG and EE goals. EFCA states the inclusion of greater demand and generation costs will double the amount already collected through the LFCR and such outcomes

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[693] AIC Opening Brief at 14.
[694] Ex TEP- 7 Hutchens RJ at 4; Ex TEP-30 Jones Dir at 78.
[695] SWEEP/WRA/ACAA Opening Brief at 19.
[696] *Id.* at 19.

are "inappropriate." [697]

7. Staff

Staff notes that in the 2012 rate case, the Company proposed an LFCR similar to the one approved for APS in Decision No. 73183 (May 24, 2012) and for UNS Gas in Decision No. 73142 (May 1, 2012). Staff states that at that time the Company asserted that it needed an LFCR to *mitigate* the negative financial impacts of complying with the Commission's energy efficiency rules and the rising number of DG resources resulting from the REST Rules.[698] Staff states that the settlement agreement that adopted the LFCR provided that the mechanism 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.[699]

Staff opposes all of TEP's proposed changes to the LFCR except for the elimination of the Fixed Cost Option. Staff believes that generation is fungible and not affected by EE and DG, if the energy is delivered to other customers – existing or new or sold off system.[700] Staff states it is important to note that the Company's Firm Load Obligations show increasing requirements in Retail Demand (net of DG and EE), shows a trend of increasing total number of customers, and further shows increasing sales to retail customers, and that the Company's Firm Wholesale Requirements are also forecasted to increase starting in 2017.[701]

Staff expressed concern that if the proposed Economic Development Rider and changes to LFCR are approved, that some generation costs could be double counted as the Company could bill existing customers for the generation costs through the LFCR and redirect that energy and capacity to a new residential or a customer attracted by the proposed economic development rates.[702] Staff also does not believe it is appropriate to recoup lost revenues due to the approval of a buy-through tariff in this case, and that it would be inappropriate to charge all customers, subject to the LFCR, for benefits

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697 EFCA Reply Brief at 19-20.
698 Staff Opening Brief at 12; Decision No. 73912 (June 27, 2013) at 8.
699 Decision No. 73912 at 6.
700 Ex S-10 Solganick Dir at 54.
701 Ex S-10 Solganick Dir at 54.
702 Staff Opening Brief at 14; Ex S-10 Solganick Dir at 55.

that a few customers are able to reap on the buy-through tariff.

Staff does not believe expanding the LFCR beyond its original purpose is appropriate, especially given that the proposed changes would expand the amount collected through the LFCR from $17.9 million to $25.7 million.[703]

8. Analysis and Resolution Regarding LFCR

We believe that the recovery of lost fixed cost revenues is best addressed through good rate design rather than a surcharge mechanism that is controversial and difficult for some ratepayers to understand. In this case, we attempt to modernize rates to better reflect cost causation and to reduce lost fixed cost revenues. Although our efforts to improve rate design may not go as far as some parties have urged to align costs and cost recovery, principles of gradualism and fairness, and the need for customer education, moderate what could otherwise be disruptive impacts due to rate design. It is not necessary that cost causation and cost recovery match exactly, but that the utility is given a fair and reasonable opportunity to recover its authorized revenue requirement in an equitable manner.

We do not find that it is reasonable to modify the LFCR as requested at this time while we are modifying rate design, except we do find it reasonable to allow TEP to recover any lost fixed cost revenues attributed to "reliability must-run generation" because these costs are related to long-term investments and not easily adjusted, and the generation may not be sold on the wholesale market. Some of the motivation for requesting a greater recovery of lost fixed costs associated with generation assets is likely due to current market conditions under which TEP is not able to sell its excess generation. By not allowing as much of the fixed costs of generation as requested, the Company is incentivized to avoid these costs if possible.

We also approve the elimination of the fixed charge option, and direct TEP to submit a revised POA for the LFCR within 60 days of the effective date of this Decision. The POA should eliminate any potential double counting of costs for any reason and be clear that any lost fixed costs associated with other potential factors on lower sales such as weather or general economic conditions are not recovered. We find further that retaining the breakout of the EE and DG portions of the charge

[703] Staff Opening Brief at 15.

provides additional information to ratepayers and there has not been sufficient reason presented that warrants changing the current practice.

C. PPFAC

1. AECC/Freeport/NS

AECC/Freeport/NS propose a 70/30 risk-sharing mechanism for the PPFAC. Under the current practice, TEP passes through 100 percent of all cost deviations for purchased power and fuel to its customers. AECC/Freeport/NS assert that without risk there is little incentive for the Company to keep power and fuel costs low, and thus believe that proper incentives are needed to produce the greatest benefit to its customers. They state their proposal is not an indictment against TEP's past procurement practices, but is a means to yield even more cost savings. They state that the goal would be to get the best possible deal in every transaction and not merely making sure the Company did not act imprudently.

In addition to the proposed 70/30 risk-sharing mechanism, AECC/Freeport/NS recommend that the Commission change the way margins from new long-term sales contracts are treated in the PPFAC. They state that prior to TEP's last rate case, margins from all wholesale transactions were credited to customers through the PPFAC, except the margins from those long-term contracts that were used in the calculation of jurisdictional demand allocations.[704] They state that as part of the 2014 settlement agreement, the PPFAC POA was changed to assign 100 percent of margins from new contracts longer than 1-year to the benefit of shareholders rather than customers. The current practice is no longer acceptable to AECC/Freeport/NS and they argue it is unreasonable in the context of the current rate proceeding. To support their position, they state that TEP's Supplemental IRP filing made September 30, 2016 shows that the Company plans to make firm sales to Navopache Electric Cooperative starting in 2017.[705] AECC/Freeport/NS state that this sales contract has implications for the jurisdictional allocation and the treatment of margins in the PPFAC from new long-term sales. They state that despite having no fixed generation costs allocated to Navopache Electric in this rate proceeding, TEP wants to retain 100 percent of the margins from this future sale with no credit to customers. They argue that

[704] AECC/Freeport/NS Opening Brief at 16.

[705] TEP Supplemental Report to 2016 Preliminary Integrated Resource Plans filed in Docket No. E-00000V-15-0094 on September 30, 2016, at 31.

flowing 100 percent of the margins to TEP for a new contract that is not allocated any non-fuel costs creates an undeserved windfall for TEP. Under AECC/Freeport/NS's proposal, the margins from this sales contract would flow back to customers who paid, or are paying, for the assets that generate these sales.[706] AECC/Freeport/NS argue that all revenue from wholesale sales, irrespective of term, should be credited against fuel and purchased power costs and included in the PPFAC, unless such sales are allocated an appropriate share of system costs, and thus the change to TEP's PPFAC POA approved in the last rate case should be reversed.

2. TEP

TEP asserts that AECC/Freeport/NS's sharing mechanism would expose TEP to fuel and power market risk for every transaction every hour of the day, and would be viewed negatively by credit rating agencies.[707] TEP contends that the current PPFAC reflects the common-sense idea that TEP should neither make a profit nor a loss on the fuel and purchased power it buys to serve its customers. TEP states that AECC/Freeport/NS's proposal would have TEP playing the market to try to prevent losses. TEP argues that neither Staff nor Mr. Higgins for AECC have found any deficiencies in TEP's fuel and purchased power practices. TEP notes that Mr. Higgins suggested that the arrangement would incentivize TEP to schedule plant maintenance at advantageous times, but TEP asserts that Mr. Higgins has no evidence that TEP does not do this.[708]

TEP strongly objects to the AECC claim that "without risk, there is little incentive for the Company to keep power and fuel costs down."[709] TEP states that it prudently executes its on-going fuel and purchased power procurement to keep these costs low, and there is not a shred of evidence to the contrary. TEP asserts that no party brought forward any procurement practice that should be changed, or any transaction that should or should not have been completed.[710]

TEP claims that the proposal which takes the projected cost of power for 2017 and would penalize the Company if its purchased power or fuel costs are greater than the projection, presents several problems including that projections are based on current information and not meant to generate

[706] AECC/Freeport/NS Opening Brief at 16.
[707] TEP Opening Brief at 51-52; Tr. at 1043-1044.
[708] TEP Opening Brief at 52.
[709] AECC/Freeport/NS Opening Brief at 15.
[710] TEP Reply Brief at 28.

profit and loss but for planning purposes. Further, TEP states that with wholesale power prices at historic lows, AECC/Freeport/NS is essentially trying to protect itself from any price increase in the event prices rise. TEP further asserts that the 2017 projections would rapidly become out of date as regional prices change and weather volatility is experienced. Moreover, TEP states that the Wyoming utility that was the model for Mr. Higgins' proposal has a large amount of hydropower which is very flexible in dispatch.[711]

Finally, TEP argues Mr. Higgins did not provide the extensive modifications to the PPFAC POA that would be required for the sharing mechanism being proposed. TEP's witness, Mr. Robey, testified that adjustor POAs take into account the degree to which things are and are not within a utility's control. For those items deemed not in the utilities' control, there are balancing components created to make up for differences in actual performance versus what was originally forecast.[712] TEP asserts that none of the details regarding these unpredictable factors within these proposed sharing mechanism were addressed by AECC or any other party in this proceeding.[713] TEP further asserts that AECC's proposal would require burdensome annual regulatory reviews that would necessitate significant changes to the POA to address a number of forecast modeling and regulatory rate complexities, and given the unsupported detail, AECC's PPFAC sharing mechanism should be rejected.[714]

TEP claims AECC's plan would have TEP focus on profits, not customers. The Company notes that RUCO supports a variation of AECC's plan with 80/20 sharing, but RUCO merely cites AECC's witness Mr. Higgins, and offers no new evidence in support of what TEP considers a risky proposal.[715] TEP argues these proposals are not about risk management or hedging as AECC's "sharing mechanism" does not measure the prudence of TEP's procurement, but is merely a test of the forecast.[716] TEP argues that the majority of fundamental drivers in a forward projection of fuel and

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711 Ex TEP-39 Robey RJ at 3-4.
712 Ex TEP-38 Robey Reb at 9.
713 TEP Reply Brief at 29.
714 TEP Reply Brief at 29.
715 *Id.* at 28, RUCO Brief at 22-23.
716 TEP Reply Brief at 28. Mr. Higgins testified that under his proposal, the Commission would approve projected purchased power and fuel costs for 2017; if the Company beats the projected costs, it gets 30 percent of the "profits"; conversely if the Company's costs are higher than the projection, the Company must absorb 30 percent.

purchase cost are outside the Company's control, including price volatility of natural gas and wholesale power, large shifts in customer usage projections, intermittent output of renewable generation resources, and unforeseen acts of nature that create market events that lead to unforeseen price spikes.[717]

Currently, short-term off-system sales are credited to customers in the PPFAC while long-term sales are accounted for in the jurisdictional allocation. TEP states that AECC/Freeport/NS are mistaken when they claim the treatment of long-term wholesale margins was changed in the last rate case. TEP states that the operation of the PPFAC did not change in the last rate case, but the settlement approved a clarification that codified the existing practice of how the PPFAC worked based on the FERC definition of wholesale power transactions. TEP states that long-term wholesale sales have received the same treatment since the inception of the Company's PPFAC in 2008.[718] TEP asserts that AECC is also mistaken when it states the 2017 wholesale transaction with Navopache was not disclosed and that no fixed generation costs were allocated to the Navopache contract.[719] TEP states that in its Rebuttal Testimony, the jurisdictional allocation demand factor was revised to include the new long-term Navopache contract which was then carried over into the revenue requirement approved in the Settlement Agreement.[720]

TEP argues that no change is warranted for the treatment of long-term off-system sales in the PPFAC, as long-term sales are FERC jurisdictional transactions and are already addressed in the jurisdictional allocation which specifically allocates a pro-rata share of the non-fuel related costs directly to long-term wholesale contract customers.[721] As such, TEP asserts its retail customers benefit from lower overall rates due to the allocation of fixed generating costs being spread over a larger customer base. TEP argues that AECC/Freeport/NS's proposal results in asymmetrical benefits for large industrial customers, as the proposal only kicks in when long-term wholesale sales increase, and would not account for reduced wholesale sales between rate cases. TEP asserts that the jurisdictional allocation would assume those revenues are still there, when in reality, the revenues would be lost.

[717] TEP Reply Brief at 29.
[718] Ex TEP-39 Robey RJ at 8; TEP Reply Brief at 30.
[719] AECC Opening Brief at 16; TEP Reply Brief at 30.
[720] Ex TEP-25 Sheehan Reb at Ex MEW-R-1; Ex TEP-3 Settlement Agreement at Attachment A, page 3 of 5.
[721] TEP Reply Brief at 31.

Thus, TEP argues AECC's proposal is one-sided, unnecessary, and contrary to how the PPFAC has worked from inception, and should be rejected. [722]

3. RUCO

RUCO recommends changing the current paradigm that allows the utility to keep all of the profits associated with power sales. RUCO asserts that it is inequitable for the Company to exclusively profit from the sale of power that that is the product of generation assets supported by retail customers.[723] Currently, TEP passes through 100 percent of the changes in base fuel and purchased costs to customers between rate cases by means of the PPFAC. RUCO agrees with Mr. Higgins that a 100 percent pass-through seriously reduces the incentive to manage its fuel and purchased power costs as well as they would be managed if the utility was exposed to the energy cost risk.[724] RUCO asserts that aligning the interest of the ratepayer and shareholder is a basic tenant of regulation, and there is no reason why the Commission should allow the misalignment to continue. RUCO proposed an 80/20 sharing of profits (80 percent of profit from these sales passed back to retail ratepayers and 20 percent retained by the Company) from long-term off-system sales, but states it would support the AECC proposed 70/30 sharing provision.[725] RUCO believes the Company should retain some incentive to make the sales because they benefit both ratepayers and shareholders.

4. Staff

Staff did not support the changes to how the PPFAC would be apportioned to rate payers as originally proposed by TEP. Staff stated there was no evidence presented to suggest that customers would benefit from the proposed changes.[726] During the hearing, the Company withdrew is request for a percentage based PPFAC and for the PPFAC to reflect a 12 month rolling average. Thus, TEP's ultimate position was to keep the PPFAC operating as it currently does. In its Closing Briefs, Staff did not take a position on the sharing proposals.

5. Analysis and Resolution of PPFAC Issues

Neither AECC/Freeport/NS nor RUCO have presented a compelling reason for us to enact a

[722] *Id.*
[723] RUCO Opening Brief at 22.
[724] Ex AECC-6 Higgins Rev Req Dir at 39
[725] RUCO Opening Brief at 23.
[726] Staff Opening Brief at 32-33.

sharing arrangement in connection with the PPFAC. TEP raised a number of reasons why such proposal appears to reward (or fail to penalize) the Company's ability to project fuel costs, rather than its ability to procure fuel or power. Those advocating for a sharing arrangement presented no evidence that such a program is needed to protect ratepayers. As RUCO noted that the ROE approved in this case does not reflect a lower risk associated with a revised LFCR, neither does it reflect the additional risk associated with the sharing proposal. The PPFAC appears to be operating appropriately and reasonably.

D. Environmental Cost Adjustor ("ECA")

1. TEP

The ECA provides recovery for environmental costs including the costs of complying with Federal environmental mandates. TEP's ECA is capped at $0.00025 per kWh, based on 0.25 percent of prior test year revenues, which amounts to about $2 million per year. TEP expects eligible compliance costs of at least $4 million per year.[727] TEP requests that the cap be increased to 0.50 percent of annual revenues. TEP also proposed changing the ECA from a $ per kWh charge to a percentage based charge to ensure that all customers classes are treated fairly when the surcharge is re-set.[728]

TEP notes that in Staff's Opening Brief it does not explain why it opposed the modification of the ECA, and argues that Staff's unsupported objection should be rejected.[729] The Company notes that RUCO has argued that TEP has not shown that it has been harmed by the under-collection of revenue and that the extra risk exposure to ratepayers from an increased cap has not been reflected in the cost of capital.[730] TEP asserts that no party has disputed TEP's forecast that environmental costs will exceed the cap, and that the risk is really caused by environmental mandate costs going up, and that the ratepayers will bear these costs either in the ECA or in the next rate case. TEP states that its generation portfolio is likely more exposed to these environmental risks than the average of the sample group used to set the ROE, and that while TEP is adjusting its generation portfolio as quickly as feasible, generation assets are long-term and TEP has little choice about the environmental costs it bears.[731]

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[727] Ex TEP-30 Jones Dir at 81.
[728] TEP Opening Brief at 54-55.
[729] TEP Reply Brief at 34.
[730] RUCO Opening Brief at 21.
[731] TEP Reply Brief at 34.

2. RUCO

RUCO recommends that the ECA not be modified. RUCO asserts that TEP has not shown that it has been harmed by the under collection of revenues under the ECA. RUCO argues that any increase in the percentage cap would expose ratepayers to more risk which has not been compensated by a reduction in the Company's return on equity.[732]

3. Staff

Staff opposes the proposed increase in the cap on the ECA and the change from an energy-based charge to a percent-based charge.[733]

4. Analysis and Resolution Concerning ECA

The parties who expressed opposition to TEP's proposal have given their arguments little space. TEP does not seek to amend what costs can be recovered in the ECA, but merely the cap to allow quicker recovery of the eligible costs. Regardless of what TEP projects, it is only able to recover those costs that are actually incurred, not its projections.[734] Thus, we find that raising the cap to 0.5 percent of test year revenues is reasonable given the evidence presented.

We do not have sufficient evidence to evaluate the effect of changing the ECA to a percentage of bill charge from a per kWh charge, and thus decline to approve such change. Within 60 days of the effective date of this Decision, TEP should file a revised ECA POA reflecting this Decision.

E. Demand Side Management ("DSM") Surcharge

1. TEP

The DSM surcharge is currently calculated as a $ per kWh charge for residential customers and a percentage charge for all other classes. TEP proposes that a percentage-based charge apply to all customer classes as TEP believes that this is simpler and more equitable.

2. SWEEP

As discussed earlier, SWEEP argues that Energy Efficiency Program costs should be recovered in base rates rather than through the DSM surcharge.

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[732] RUCO Opening Brief at 21.
[733] Staff Opening Brief at 33.
[734] See Decision No. 73912 at Attachment G to the settlement agreement (ECA POA).

3. **Staff**

Staff recommends that in TEP's next DSM Plan, the Company reassess its billing charge so that all customers, both residential and non-residential are billed based on an energy-based charge.[735] Staff recommends that the Company update its DSM POA so that it is consistent with all existing decisions and submit it for Commission approval within 60 days of a Decision in this matter.

4. **Analysis and Resolution Concerning DSM**

TEP wants all ratepayers to be assessed for approved DSM programs on a percentage of bill basis, and Staff wants all customers to be assessed on a "per kWh" basis. We agree that the methodology should be consistent across rate payers in order to assure fairness. We do not have sufficient information in this docket to assess the ratepayer impacts of either proposal. We direct TEP and Staff to address this issue in the Company's next application for a DSM Surcharge reset.

It is the intent of this Commission that savings contemplated in DSM Plans submitted by TEP should come increasingly from the period of system peak demand and should increase the peak demand reductions from DSM. As such, TEP's DSM Plans should increase the focus on EE, demand response ("DR"), and load management programs that reduce customer energy demand during the period of system peak demand. Specifically, TEP should:

1. Make its best effort to increase the peak demand reductions (MW) from EE programs in 2017 by 10 percent compared to the 2016 peak demand reductions from EE programs. Such programs must consider advanced technologies that can reduce or manage peak demand in addition to reducing energy use, such as wireless thermostats, energy management systems, and controls, many of which were highlighted during the Commission's technology workshops.
2. Make its best effort to increase the peak demand reduction capability (MW) from DR and load management programs (not including Time-of-Use or other rates) in 2017 by 15 percent compared to the reported 2016 peak demand reductions form DR and load management programs. Such programs must consider facilitating energy storage technology.
3. In its 2018 DSM Implementation Plan, TEP will increase the peak demand reductions

[735] Staff Opening Brief at 33; Ex S-22 Van Epps Surr at 3-6.

(MW) form EE programs in 2018 and increase the peak demand reduction capability (MW) from DR and load management programs (not including Time-of-Use or other rates) in 2018 compared to the reported 2016 peak demand reductions from DR and load management programs. Such programs must consider facilitating energy storage and other advanced technologies.

4. In future DSM Implementation Plans, TEP will further increase the focus on peak demand reductions (MW) from EE, DR, energy storage, and load management programs that reduce customer energy demand during the period of system peak demand.

As part of its 2018 DSM Plan, TEP is to develop and propose to the Commission, for approval, within 120 days of the effective date of this Order, a residential or feeder level DR or load management program that facilitates residential or feeder level energy storage technology. This technology should primarily aid residential customers to reduce their electricity demand during periods of system peak demand. TEP should anticipate spending $1.3 million on this program, which may be funded using any unspent DSMAC collections.

Residential customers who participate in the program will be placed on advanced, time-differentiated rate plans. This advanced rate would include proper price signals based on the principles of: 1) an On Peak/Off Peak rate with sufficient rate spread between the two time periods, 2) a manageable On Peak window to allow for adequate "peak shaving," and 3) proper price signals based on seasonality. As such, TEP will use rate plans and tariffs deemed appropriate by the Company for participants in this program. In Phase 2, the Commission also wishes to consider an optional rate designed to encourage customers to reduce peak demand and assist the grid through the deployment of distributed solar plus storage devises.

Given the developing nature of this energy storage technology program, the Commission will waive its normal benefit-cost threshold and revisit the program and measures in the Company's 2019 DSM Plan. However, TEP will report the benefit-cost results of the program and of each energy storage measure as part of its regular reporting process for DSM.

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F. Miscellaneous Recommendations

1. Renewable Energy Standard Tariff ("REST")

Staff recommends that within 60 days of the effective date of this Decision, the Company file a POA for its REST adjustor consistent with the POA filed for UNSE. Staff further recommends that the POA incorporate all existing pertinent Commission decisions. TEP does not oppose this recommendation, and thus, we adopt it.

2. White Mountains Solar Facility

The White Mountain Solar Facility near the Springerville Generating Station was placed in service in December 2014 at a total unbundled cost of $43,193,061. The output of the facility is used primarily to power the well-field pumps.

Staff states that during the course of the Value of DG proceeding issues surfaced associated with the Company's production data for this facility and Staff's calculated capacity factor. As a result, Staff requested that the Company provide monthly information about the production of the facility until a final decision in this matter, so that Staff can monitor the performance of the facility.[736]

The Company does not object to providing Staff with the requested information.[737]

3. Modification of Compliance Matters

TEP identified several Commission orders that set compliance requirements which TEP believes are outdated and either moot, have been supplanted by subsequent orders, or are no longer necessary.[738] Based on Staff's review of the request, TEP has revised its request to reflect Staff's position.[739] Thus, currently, TEP seeks to eliminate the following compliance filings:

1. Reporting requirements related to the Retail Electric Competition Rules, A.A.A R14-2-1608(A) (Systems Benefit Charge Filing); A.A.C. R14-2-1613(A) and (B) (Annual Electric Competition filing); R14-2-1617 (A), (C), (D), and (G) (Annual Consumer Information Label), and R14-2-1617 (G) and (E) (Annual Disclosure Report).
2. Requirement of Decision No. 65347 (November 1, 2001) to file a report every five years

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[736] Staff Opening Brief at 34.
[737] Tr. at 921.
[738] TEP Opening Brief at 55.
[739] Ex TEP-34 Smith Rebuttal at 6; Ex S-17 Connolly Dir at 10-16.

listing potential improvements (and their costs) to Springerville units 1 and 2 that reduce emissions.

3. Filing an Annual Cost of Containment Report required initially by Decision No. 59594 (March 29, 1996).
4. Filing of a Full Decoupling Report in connection with the LFCR annual adjustment required by Decision No. 73912 (June 27, 2013).
5. Filing an Annual Letter on TEP's Code of Conduct required by Decision No. 62767 (August 2, 2000).
6. Filing an Annual Statement Preparedness Report pursuant to the Cyprus Sierrita Certificate of Environmental Compatibility ("CEC") required by Decision No. 69680 (June 28, 2007).
7. Filing an Annual Sign Replacement Report, pursuant to the Cyprus Sierrita CEC required by Decision No. 69680.
8. Filing an Annual Self-Certification Letter, pursuant to the Gateway Substation CEC required by Decision No. 64356 (January 15, 2002).
9. Develop a data base of existing renewable energy resources within its service area within six months from the effective date of Decision No. 58643 (June 1, 1994), with inventories revised and submitted to Staff each year as part of the historical data filings required under the IRP rules (R14-2-703A&B).

No party objected to TEP's revised requests.

TEP requested to be relieved of complying with the above-referenced Electric Competition Rules because they are not relevant given that there is no electric competition in Arizona, and because a significant portion of the Rules were vacated by the *Phelps Dodge* decision.[740] Staff concurs with TEP's request. Rule 1608 (A) requires an annual report on system benefits (i.e. programs for low-income, DSM, consumer education, etc.); Rule 1613 (A) and (B) requires a report on competitive service offerings; Rule 1617 requires reports on resource portfolios and consumer labeling. The reports required by these rules are not necessary at this time. Thus, we suspend any reporting requirements

[740] Ex S-16 Connolly Dir at 10.

under the above-referenced rules until further order.

Decision No. 65347 requires TEP to file a report every five years on environmental improvements at the Springerville facility. TEP states that since the issuance of Decision No. 65347, there has been substantial activity at the federal level regarding various emission standards, including the adoption of the Clean Power Plan, and that with the approval of the ECA, the Commission can track and review environmental compliance investments by TEP. Staff agrees that a report every five years is no longer needed. We agree that the ECA provides the Commission with timely reports on environmental compliance investments, and thus relieve TEP of continuing the five-year report pursuant to Decision No. 65347.

Decision No. 59594 was a TEP rate case filed in 1995 in which the Commission approved a moratorium on filing rate cases before January 1, 2000. Since Decision No. 59594 was issued, TEP has had several rate cases in which the prudency of TEP's costs have been reviewed. The Cost Containment Report required by Decision No. 59594 is no longer needed and we relieve TEP of the obligation to make this compliance filing.

In TEP's last rate case, the Commission approved the LFCR and ordered TEP to include a full decoupling report with its annual LFCR filing to reflect what rates and average utility bills would have been if full revenue decoupling have been approved. [741] TEP asserts that compiling a full decoupling report in connection with its LFCR is burdensome and unnecessary. Staff agreed that if TEP has no intention of asking for full decoupling that the Commission eliminate this reporting requirement. It appears that when the Commission approved the LFCR as a partial decoupling mechanism, it was interested in data that would allow it to compare the impact of the LFCR mechanism with full revenue decoupling. Since that time, neither the Commission nor TEP has sought to move toward full decoupling. If in the future, either the Commission or TEP seeks to study implementation of full decoupling, the Commission can request TEP to provide any information necessary to evaluate the impacts of full decoupling. Thus, until further order of the Commission, we adopt Staff's recommendation to eliminate the annual full decoupling report for TEP.

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[741] *See* Decision No. 73912 at 75.

Decision No. 62767 requires TEP to file an annual report listing all extraordinary circumstances excusing TEP's compliance with the Code of Conduct approved in that Decision. TEP states that the requirement to file an Annual Letter pursuant to Decision No. 62767 has been superseded by TEP's new Code of Conduct approved in Decision No. 75033 (April 23, 2015). Staff notes that Decision No. 75033 approved a UNS Energy Code of Conduct which is applicable to UNS Energy's affiliates, including TEP. Decision No. 75033 finds that the Code of Conduct at subject therein "updates UNS Energy's previously approved Code of Conduct," Staff states that the updated Code of Conduct does not include a reporting requirement, and thus, Staff believes it is reasonable to conclude that an annual report is no longer necessary.[742]

Decision No. 75033 provides: "The Code of Conduct updates UNS Energy's previously approved Code of Conduct to reflect the current conditions, including the acquisition of UNS Energy by Fortis." Staff's position indicates that it does not require the annual letter pursuant to Decision No. 62767. We concur with Staff's conclusions and find that the annual reporting requirement concerning the Code of Conduct in Decision No. 62767 has been superseded and no longer required.

Decision No. 69680 (June 28, 2007) requires TEP to file an Annual Summer Preparedness Report for the Cyprus Sierrita Substation CEC that documents the ability of TEP's Green Valley area 46 kV system to timely restore service to all customers served from the Green Valley and Canoa Ranch Substations following an outage on the 138 kV line. This condition was to remain in effect until a new 138 kV transmission line was built from the South Substation to Cyprus Sierrita Substation. On June 27, 2013 in Docket No. L-00000C-95-0084, TEP filed a Notice of Completion of Certificated project in which it stated that the construction of the 138 kV transmission line had been completed in its entirety and energized as of June 25, 2013. Staff believes that given the construction of the line has been completed, the reporting requirement is no longer in effect and TEP's requested relief should be granted.

In Decision No. 69680 TEP was also ordered to submit annually a Sign Placement report that documented the location of signs in public rights-of-way giving notice of the construction of the 138

[742] Ex S-16 Connolly Dir at 13.

kV transmission line built from South Substation to Cyprus Sierrita Substation in the "Phase Two" corridor of the CEC. On June 27, 2013, In Docket No. L-00000C-95-0084, TEP filed a notice of Completion of Certificated Project in which it stated that the construction of the 138 kV transmission line had been completed. Staff believes that given the construction of the line is complete, the reporting requirement is no longer needed and TEP's requested relief should be granted.[743] We agree that both reporting requirements identified are no longer relevant and can be eliminated.

Decision No. 64536 (January 15, 2002) requires TEP to file an Annual Self-Certification Letter identifying which conditions have been met in the CEC authorizing construction of a double circuit, 345 kV transition line running from TEP's South 345 kV Substation to a proposed TEP Gateway Substation in Nogales with a 115 kV interconnection to the 115 kV Valencia Substation and a 345 kV line to the international border. In Decision No. 73625 (December 12, 2011), issued in response to the Seventh Biennial Transmission Assessment, Staff's recommendation to suspend efforts to upgrade the transmission construction for Santa Cruz County due to the high cost of the capital upgrades was adopted. Therefore, Staff recommends granting TEP's request to be relieved of this obligation. We agree.

In Decision No. 58643 (June 1, 1994), TEP was required to develop a data base of existing renewable energy resources within its service area and to revise it annually as part of the historical data filings required under the IRP rules (A.A.C. R14-2-703 (A) and (B)). TEP states this requirement was based on the previous version of the IRP rules which were subsequently suspended and then superseded in 2010. TEP provides similar information in accordance with current IRP rules. Staff states that TEP's Renewable Energy Resources are detailed in its most recent IRP Plan filing, dated April 1, 2014, in Docket No. E-00000VC-13-0070.[744] The current rules have rendered this directive in the 1994 Order unnecessary, and TEP should be relieved of an obligation to file this separate report.

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

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[743] Ex S-16 Connolly Dir at 15.
[744] *Id.* at 16.

FINDINGS OF FACT

Procedural History

1. On November 5, 2015, TEP filed a Rate Case Application in Docket No. E-01933A-15-0322. In support of the Application, TEP filed the Direct Testimony of David Hutchens, Susan Gray, Michael Sheehan, Carmine Tilghman, Kenton Grant, Ann Bulkley, Ronald White, Frank Marino, Dallas Dukes, Craig Jones, and Denise Smith.

2. On December 7, 2015, Staff notified TEP that its Application met the sufficiency requirements of A.A.C. R14-2-103, and classified the Company as a Class A utility.

3. On December 7, 2015, TEP filed a Motion for Procedural Schedule, proposing a schedule for the filing of testimony and a hearing in this matter.

4. By Procedural Order dated December 14, 2015, the Rate Case was set for hearing to commence on August 31, 2016.[745]

5. On February 23, 2016, TEP filed an affidavit attesting that notice of the Rate Case hearing was published in the *Arizona Daily Star* on January 12, 2016, and mailed as a bill insert to TEP customers beginning January 12, 2016 and ending on February 9, 2016.

6. Intervention in the Rate Case has been granted to RUCO, Pima County, Freeport, AECC, IBEW, NS, AIC, Vote Solar, Sierra Club, TASC, EFCA, APS, the Arizona Solar Energy Industries Association, the Arizona Utilities Ratepayers Alliance, Wal-Mart, Kroger, WRA, SWEEP, ACAA, SOLON, Arizona Competitive Power Alliance, DOD, SAHBA, TM, Arizona Solar Deployment Alliance, and the following individuals: Kevin Koch, Bryan Lovitt and Bruce Plenk.

7. By Procedural Order dated April 6, 2016, the Rate Case was consolidated with TEP's 2016 Renewable Energy Standard and Tariff Implementation Plan.

8. On June 3, 2016, Direct Testimony, except that related to Cost of Service and Rate Design was filed by: RUCO for Robert Mease, Jeffrey Michlik and Frank Radigan; Wal-Mart for Gregory Tillman; SWEEP for Jeff Schlegel; DOD for Michael Gorman; WRA for Steven Michel;

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[745] The December 7, 2015 Procedural Order adopted the proposed hearing schedule, but recognized that the timing might not permit a final order to be entered prior to the deadline established pursuant to A.A.C. R14-2-103, and thus, extended the deadline for a final order until December 31, 2016. The Procedural Order also recognized that the length of the hearing or other unforeseen events could further affect the deadline and timing to the implementation of new rate. See December 14, 2015 Procedural Order at 2 and 8.

IBEW for Scott Northrup; Sierra Club for Patrick Luckow; and Staff for David Parcell, Roxie McCullar, Eric Van Epps, Candrea Allen, Donna Mullinax and Michael McGarry.

9. On June 21, 2016, EFCA filed a Motion for Procedural Conference expressing concern based on events in the recent UNS Electric and Trico Electric Cooperative rate cases that parties in the current proceeding might attempt to amend the Application or introduce new witnesses and studies too close to the hearing to provide other parties a fair opportunity to prepare.

10. On June 21, 2016, TEP filed an Opposition to EFCA's Motion denying that circumstances in the UNS Electric or Trico proceedings were unusual or prejudicial and arguing that EFCA's Motion is inconsistent with long-standing Commission practice, speculative and premature.

11. On June 22, 2016, EFCA filed a Reply in Support of its Motion.

12. By Procedural Order dated June 24, 2016, EFCA's Motion was denied on the grounds it would not be appropriate to pre-judge the appropriate response to events that had not yet occurred.

13. On June 24, 2016, Direct Testimony related to Cost of Service and Rate Design was filed by: RUCO for Frank Radigan and Lon Huber; DoD for Maurice Brubaker; APS for Ahmad Faruqui and Charles Miessner; AIC for Gary Yaquinto; Wal-Mart for Chris Hendrix and Gregory Tillman; NS for Greg Bass; SOLON for Brian Seibel; Vote Solar for Briana Kobor; ACAA for Cynthia Zwick; EFCA for Mark Garrett; SWEEP and WRA for Brandon Baatz; Freeport, AECC and NS for Keven Higgins; and Staff for Howard Solganick, Michael McGarry, Robert Gray, Matt Connolly and Eric Van Epps.

14. On June 27, 2016, Kroger filed the Direct Testimony related to Cost of Service and Rate Design of Stephen Baron.

15. On June 28, 2016, Keven Koch filed Direct Testimony.

16. On July 25, 2016, TEP filed the Rebuttal Testimony of Mr. Hutchens, Ms. Gray, Mr. Grant, Ms. Bulkley, Mr. Marino, Mr. David Lewis, Mr. Sheehan, Mr. Robey, Mr. Mark Mansfield, Mr. Tilghman, Mr. Dukes, Dr. H. Edwin Overcast, Mr. Jones, Mr. Richard Bachmeier, and Ms. Smith.

17. On July 28, 2016, Staff filed Notice of Settlement Discussions. Also by Procedural Order dated July 28, 2016, TEP was directed to confer with the parties in order to submit a proposed witness schedule.

18. By Procedural Order dated August 12, 2016, TEP was directed to provide notice of a public comment meeting to take place on August 31, 2016 at Tucson High School commencing at 6:00 p.m.

19. On August 15, 2016, TEP filed a Settlement Agreement Regarding Revenue Requirement and a Motion to Modify Procedural Schedule, seeking to extend the start of the hearing in order to provide time to file testimony on the settlement.

20. By Procedural Order dated August 17, 2016, the hearing was rescheduled to commence on September 8, 2016, a pre-hearing conference set for September 2, 2016, and the pre-filed testimony deadlines extended in order to provide for pre-filed testimony in support of, or in opposition to, the Settlement Agreement.[746]

21. On August 18, 2016, TEP filed a Motion for Procedural Order to Modify the Scope of the Evidentiary Hearing. TEP noted that on August 18, 2016, the Commission issued Decision No. 75697 in the UNSE rate case which deferred several issues (including but not limited to net metering changes and proposed mandatory three-part rates for DG customers) to a "Phase 2" proceeding that would commence following the issuance of a final Order in the Commission's Value of DG Docket. TEP proposed that the current proceeding also be bifurcated into two phases, with Phase 2 addressing mandatory three-part rates for DG customers and proposed changes to net metering and Phase 1 addressing the revenue requirement and other "non-DG" issues.

22. By Procedural Order dated August 22, 2016, it was ordered that issues related to changes in net metering and rate design for new DG customers would deferred to Phase 2, at a time to be determined following a final decision in the Value of DG docket. As a result, any Surrebuttal and Rejoinder testimony related to Phase 2 issues would also be deferred to a date to be determined.

23. On August 23, 2016, TEP filed an Affidavit of Publication indicating that notice of the August 31, 2016 public comment meeting was published in the *Arizona Daily Star* on August 22, 2016.

24. On August 25, 2016, Wal-Mart filed Surrebuttal Testimony for Mr. Tillman; Keven Koch filed Surrebuttal Testimony; Kroger filed Rebuttal Testimony of Mr. Barron; DOD filed

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[746] An omission in the August 17, 2016 Procedural Order was corrected by Procedural Order dated August 18, 2016.

Surrebuttal Testimony of Mr. Gorman; AIC filed the Direct Testimony in support of the Settlement Agreement and Surrebuttal Testimony of Mr. Yaquinto; NS filed the Surrebuttal Testimony of Mr. Bass; SOLON Filed the Surrebuttal Testimony of Mr. Seibel; Vote Solar filed Surrebuttal Testimony of Ms. Kobor; EFCA filed the Surrebuttal Testimony of Mr. Garrett; ACAA filed the Surrebuttal Testimony of Ms. Zwick; SWEEP filed the Surrebuttal Testimony of Mr. Schlegel and Mr. Baatz; WRA filed Surrebuttal Testimony for Stephen Michel; IBEW filed the Surrebuttal Testimony of Mr. Northrup and Sarita Morales; AECC, Freeport and NS filed the Surrebuttal Testimony of Mr. Higgins; Freeport filed the Surrebuttal Testimony of Michael McElrath; RUCO filed the Surrebuttal and Settlement Testimony of Mr. Radigan, Mr. Huber, Mr. Mease, and Mr. Michlik

25. On August 26, 2016, Staff filed the Surrebuttal Testimony and Testimony in Support of the Settlement of Ms. Allen, Mr. Connolly, Mr. Van Epps, Mr. Gray, Mr. Liu, Mr. Elijah Abinah, and Mr. Solganick.[747] The same date, the Sierra Club filed A Notice of Support for the Settlement Agreement.

26. On August 30, 2016, after conferring with the other parties, TEP filed a proposed witness schedule.

27. On August 31, 2016, at the time and place of the originally scheduled hearing, the Commission convened a public comment session at its offices in Tucson; later that day the Commission convened another public comment session at 6:00 p.m. at Tucson High School, in Tucson, Arizona. The Commission received a large number of comments, in-person and in writing, in connection with this docket.

28. On September 1, 2016, TEP filed the Rejoinder/Reply Testimony in Support of Settlement Agreement of Mr. Hutchens, Ms. Gray, Ms. Bulkley, Mr. Robey, Ms. Smith, Dr. Overcast, Mr. Jones, and Mr. Bachmeier.[748]

29. A pre-hearing conference convened on September 2, 2016 to discuss the conduct of the hearing.

[747] Staff requested an extension of time to file its testimony on August 25, 2016, which one-day extension was granted by Procedural Order dated August 26, 2016.

[748] On September 2, 2016, TEP filed Exhibit JRJ-R-1 which was inadvertently omitted from the Rejoinder Testimony of Mr. Robey.

30. On September 7, 2016, TEP filed an Errata to the Settlement Agreement to clarify/correct Section 2.2 regarding the base fuel rates and Attachment A to provide additional language on settlement positions and to correct a typographical error to Transportation Expense.[749]

31. The evidentiary hearing convened before a duly authorized Administrative Law Judge ("ALJ") on September 8, 2016, and continued for 11 additional days, concluding on September 23, 2016. Following the conclusion of the hearing, the ALJ took the matter under advisement pending the submission of Closing Briefs and updated Schedules.

32. On September 15, 2016, as requested by the ALJ, EFCA filed the Supplemental Testimonies of Mr. Garrett and Mr. Beach.

33. On September 23, 2016, Staff docketed a Memorandum clarifying Staff's position on including costs of TEP's White Mountain Solar Facility in the rates as part of the Settlement Agreement. Staff expressed comfort with the current proposed treatment in rates, but in TEP's next rate case if necessary.[750]

34. On September 26, 2016, TEP docketed Notice that in accordance with the Settlement Agreement, it was filing a copy of the Form 8-K notice of the completion of its purchase of the 50.5 percent interest in SGS 1.

35. On September 29, 2016, a Letter to the Docket from Commissioner Forese was docketed, expressing an interest in expanding Arizona's transmission capacity to Mexico, and requesting relevant parties to provide a report on the viability of efforts to increase economic development to the benefit of ratepayers.

36. On October 14, 2016, TEP filed Updated Schedules.

37. On October 24, 2016 Bruce Plenk filed an Opening Brief.

38. On October 28, 2016, DOD filed an Opening Brief.[751]

39. On October 31, 2016, Opening Briefs were filed by TEP, RUCO, AECC/Freeport/NS, DoD, Wal-Mart, SAHBA, Kroger, TM, EFCA, SOLON, AIC, SWEEP/WRA/ACAA, Vote Solar and

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[749] The copy of the Settlement Agreement attached to this Order is a corrected version of the Agreement.
[750] The White Mountain Solar Facility is addressed in Staff witness Liu's Surrebuttal Testimony. *See* Ex S-19.
[751] On October 27, 2016, DoD/FEA filed a Notice of Erratum to Hearing Transcript correcting the Response of its witness Brubaker's response on page 255, line 12 of the Hearing Transcript.

Staff.

40. On November 10, 2016, Commissioner Tobin docketed a letter to the parties seeking additional information from TEP and TM regarding the LGS-13 and GS-11F tariffs.

41. On November 14, 2016, Reply Briefs were filed by TEP, RUCO, AECC/Freeport/NS, Vote Solar, EFCA, TM, SWEEP/WRA/ACAA, DOD, AIC, SOLON and Staff.

42. On November 29, 2016, TEP filed a response to Commissioner Tobin's letter.

43. On December 15, 2016, TM filed its response to Commissioner Tobin's letter.

44. The Settlement Agreement attached hereto as Exhibit A, was entered into by TEP, Staff, RUCO, Freeport, AECC, AIC, WRA, Wal-Mart, NS, Kroger, and Sierra Club. As discussed herein, the Settlement Agreement resolves the revenue requirement portion of the Rate Case. The settling parties agreed on a FVRB of $2,843,985,854, which purports to the average of an OCRB of $2,045,203,460 and RCND of $3,633,027,972; a FVROR of 5.35 percent, which includes a rate of return on the fair value increment of 1.0 percent, and based on a capital structure containing 49.97 percent debt and 50.03 percent common equity, with a return on common equity of 9.75 percent and cost of long-term debt of 4.32 percent. The Settlement Agreement provides for a base fuel rate of $0.032559, and provides that the non-fuel base rate increase includes $15,243,913 associated with the operating costs of TEP's 50.5 percent share of SGS Unit 1 which TEP acquired in September 2016. Other major terms include adjusting the depreciation rates for San Juan Generating Station Unit 1 to reflect six years and adjustment to the depreciation rates on TEP's distribution plant to offset the depreciation rates for San Juan Unit 1; and a $5 million write down of the Company's headquarters building.

45. The settlement discussions were open and transparent. Only DOD objected to the Settlement Agreement, arguing that the Cost of Equity should not exceed 9.5 percent. SWEEP did not oppose the Settlement, but argued that the costs of the Commission-approved DSM and EE programs should be included in base rates rather than recovered from the DSM adjustor mechanism. EFCA objected to assets, totaling approximately $16,000, associated with the TORS pilot program being included in rate base prior to under-going a prudency review.

46. As discussed herein, a Cost of Equity of 9.75 percent is reasonable for purposes of this

Rate Case, as is the recovery of DSM and EE programs through the DSM adjustor at this time. Furthermore, performing a prudency review on a single TORS asset, representing $16,000 out of a total approved program of $10 million, would not yield meaningful results, and thus it is reasonable to defer the prudency review of the TORS program to TEP's next rate case.

47. The Settlement Agreement contains a computation error affecting the FVRB, as the average of the OCRB and RCND is $2,839,115,716 ($4,870,138 less than stated in Section 2.5 of the Agreement). As discussed herein, we approve the full $81.5 million revenue requirement increase from the Settlement Agreement, with an adjusted Fair Value Rate of Return of 5.35 percent. With this modification, the terms of the Settlement Agreement are fair and reasonable and hereby approved.

48. The evidence does not support changing the current method of recovering the costs of Commission-approved DSM or EE programs, however, it is reasonable to require TEP to provide information to its customers concerning the composition of its resource portfolio, including EE, as suggested by SWEEP in this proceeding.

49. The allocation of the increase in non-fuel revenue authorized by the approval of the Settlement Agreement among the various rate classes, as discussed herein, is fair and reasonable.

50. It is reasonable that TEP offer four options for residential rates -- a standard two-part rate, a two-part TOU rate, a three-part rate and a three-part TOU rates. Furthermore, it is reasonable that the standard two-part Residential rates include a BSC of $13 per month and three volumetric tiers of energy charges, and that Residential TOU rates be comprised of a $10 BSC and two volumetric tiers.

51. It is reasonable that the two-part TOU rates will be the default for new residential customers, although TEP shall inform all customers of the rate design options available to them. However, the default status of the TOU rate will not take effect until TEP files a notice with Docket Control that it has completed the necessary revisions to its billing systems, but the default must take effect no later than January 1, 2018.

52. The Company's proposal to implement discounts for Lifeline customers instead of a separate tariff is reasonable, but to protect customers currently on frozen Lifeline rates from unreasonably severe rate impacts, it is in the public interest for TEP to review individual bill impacts for those frozen Lifeline customers identified by Staff as being particularly susceptible to unreasonable

impacts. If any of these frozen Lifeline customers would see impacts greater than 12 percent of their average annual monthly bill, the proposal may be burdensome, and TEP should either increase the discount for these customers to fall within this guideline or keep these customers on their current frozen rate.

53. It is reasonable to require TEP to implement an automatic Lifeline enrollment program by December 31, 2017, or to file a report with the Commission explaining why such streamlined process could not be implemented, or would not be cost-effective or beneficial.

54. It is reasonable to direct TEP to provide testimony in its next rate case on whether a tiered discount based on the Federal Poverty Guidelines as suggested by ACAA would be an improvement over the current Lifeline discounts.

55. The Company's proposed SGS rate designs are reasonable, except that the BSC for single phase SGS customers should be $25.

56. It is reasonable to require TEP to develop a customer information portal as suggested by Staff, and submit a comprehensive customer education plan for Residential and SGS customers providing them with information on managing their demand and energy consumption as well as means to compare various rate options, within 90 days of the effective date of this Decision.

57. It is reasonable to create a new MGS class as proposed by the Company, with a $40 BSC and three-part rate design, except that it is not reasonable to include a demand ratchet in the rate design for the Class. It is reasonable that the transitional two-part MGS rates shall remain in effect for 12 months following Commission approval of a detailed transition plan that will include how TEP will communicate with affected customers, what demand information will be made available, and how it will be accessed, as well as possible training or education modules and a plan for transitioning existing SGS customers whose increased consumption in the future would qualify them for the MGS Class. The transition plan shall also include the process for transitioning customers form the MGS Class to the LGS Class. It is reasonable to require TEP to submit its transition plan for Staff review and Commission approval within 90 days of the effective date of this Decision, and for Staff to prepare its recommendation on the plan within 90 days of its filing.

58. DG systems that have filed for interconnection to TEP's distribution system before the

effective date of the Decision in Phase 2 shall be considered to be fully grandfathered and continue to utilize currently implemented DG-related rate design and net metering for a period of 20 years from the date a DG system in interconnected, except that DG customers who file for interconnection after the effective date of this Decision shall be subject to the DG meter charges approved herein. Existing customers with DG systems will be subject to currently-existing rules and regulations impacting DG. Current commercial DG customers who will be transferred to the MGS or LGS Class shall be grandfathered on the MGS Class transition two-part rate design, subject to currently-existing rules and regulations impacting DG, with an option to adopt the MGS or LGS three-part rates.

59. It is reasonable to retain the governmental discount, but reduce it to 12 percent, and to adopt an additional 25 percent step-down mechanism, thereby reducing the governmental discount by 25 percent each year until the next rate case. Within 12 months of the effective date of this Order, TEP shall submit to the Commission a POA that details how the additional revenues TEP recovers as a result of the declining discount will be returned to other customers. In its next rate case, TEP should provide testimony on the reasons for this discount and whether or not its continuation is in the public interest.

60. The Company's proposed rate design for the LGS Class is reasonable, however the demand ratchet mechanism featured in this rate design may be incompatible with battery storage technology. Therefore, an optional rate that does not include the demand ratchet mechanism should be made available for those LGS customers electing to adopt storage technology. LGS customers who participate in this optional rate will be placed on advanced, time-differentiated rate plans. This advanced rate would include proper price signals based on the principles of: 1) an On Peak/Off Peak rate with sufficient rate spread between the two time periods, 2) a manageable On Peak window to allow for adequate "peak shaving," and 3) proper price signals based on seasonality. As such, TEP will use rate plans and tariffs deemed appropriate by the Company for participants in this rate design.

61. It is reasonable to revise the Company's proposed rate design for the LPS, and 138 kV Classes to include a BSC of $2,000 and $3,000, respectively.

62. It is reasonable for the rate design portion of this case to be held open for 18 months after the effective date of this Order for all rate classes in order that the Commission can address any unintended consequences that may result from the rate designs approved herein.

63. Because of the potential adverse impacts on non-participating ratepayers, it is not in the public interest to approve a buy-through tariff at this time.

64. Approving TEP's proposed EDR is in the public interest.

65. It is reasonable to approve TEP's proposed Pre-Paid Energy Service as a pilot program as recommended by Staff. It is also it the public interest to direct TEP to explore the development of an enhanced customer education, information and feedback program that can be made available to all residential customers to manage and reduce their energy bills, and to discuss its efforts in the Company's next EE Implementation Plan.

66. It is reasonable under the specific circumstances of this case to allow TM to take service under the proposed GS-M-F tariff.

67. Residential and SGS DG customers who file for interconnection prior to the Decision in Phase 2 should be grandfathered on their current rate designs and net metering tariffs for a period of 20 years from the date their systems are interconnected.

68. It is reasonable to adopt RUCO's proposed RPS Credit Option during the interim period from the effective date of this Order until a final determination in Phase 2 on whether the option should be offered following a Decision in Phase 2.

69. It is reasonable that new Residential and SGS DG customers who submit applications for interconnection after the effective date of this Order shall be subject to a charge for the incremental cost of their bidirectional meter of $2.05 for Residential customers and $0.35 for SGS customers.

70. It is reasonable to review the continued reasonableness of the RPS Credit option and the second meter charge in Phase 2 of this proceeding.

71. The Company's final position on the proposed revisions to its Rules and Regulations are reasonable and should be adopted.

72. The record does not support expanding the LFCR as proposed by the Company, however, it is reasonable and in the public interest to allow the inclusion of any lost fixed cost revenues resulting from must run generation assets, and expanding the cap on the LFCR to 2 percent as a result. It is reasonable to eliminate the fixed charge option under the current LFCR tariff. TEP should be directed to submit a revised Plan of Administration for the LFCR to reflect these modifications within

60 days of the Decision in this matter.

73. A risk-sharing arrangement for the PPFAC is not in the public interest.

74. An increase in the cap on the ECA to 0.5 percent as proposed by the Company is reasonable to allow the timely recovery of eligible costs and to avoid future rate payers paying for current environmental costs.

75. The record in this proceeding is not sufficiently complete to support changing the method for assessing the DSM surcharge, and that it is reasonable to require TEP and Staff to address a uniform methodology for assessing the DSM surcharge in TEP's next application for a DSM Surcharge reset.

76. It is reasonable to adopt Staff's recommendation that within 60 days of the effective date of this Decision, the Company file a Plan of Administration for its REST adjustor that incorporates all existing pertinent Commission decisions, and is consistent with the POA filed for UNSE.

77. As discussed herein, it is reasonable to eliminate those compliance filings identified by the Company and as recommended by Staff.

78. In recent days, we have learned that there are plans to shut down the Navajo Generating Station ("NGS") in 2019. NGS is jointly owned by Salt River Project, Arizona Public Service Company, and TEP.

79. The Commission is concerned that closing NGS may have serious consequences for the entire state.

80. Closing NGS will require our load serving entities to replace NGS coal-fired generation with other resources. It appears that the initial intent is to replace those resources with natural gas. Although natural gas prices may be favorable at the present time, there are no guarantees that those prices will remain constant.

81. The choice to transform Arizona's resource portfolio from a balanced approach (that includes a mix of resources) to a more limited approach (that relies disproportionately upon natural gas) will expose our citizens to the price volatility associated with natural gas and increased uncertainty regarding grid reliability, especially because there is currently no natural gas storage facility capable of holding emergency reserves in the event of a gas outage inside or outside of the state.

82. We are also concerned that shuttering NGS may increase the costs borne by consumers of Central Arizona Project ("CAP") water. As a result, the closure of NGS is likely to negatively impact water rates.

83. Finally, we must acknowledge the high potential for general economic devastation that may be experienced throughout the entire state if NGS were to close. The negative economic impacts to the Hopi and Navajo communities, as well as to the Kayenta Mine, are too obvious to require elaboration.

84. Under these circumstances, it is difficult for the Commission to sit idly by as these events unfold, and we anticipate that the public will also want a thorough explanation of these developments.

85. TEP is a co-tenant under the leasing arrangements for the operation of NGS. It is the Commission's understanding that there are multiple committees among the co-tenants that address operational and other issues that arise under the co-tenancy agreement. It is also our understanding that one or more of these committees will be responsible for addressing any plans to close NGS and that TEP will have representatives on these various committees.

86. The co-tenancy agreement also provides for a right of first refusal among the existing co-tenants if any one of the remaining co-tenants wishes to transfer its ownership interest in NGS to any other entity.

87. Without a full understanding and valuation of the reasons for closing NGS, we are uneasy about these developments, and we therefore direct TEP to file a report in its IRP docket by April 1, 2017. In its report, TEP shall address the following issues in detail:

(a) How does the co-tenancy agreement govern the potential closure of the NGS?

(b) How does the right of first refusal affect the potential closure of NGS?

(c) Has TEP considered purchasing additional shares in NGS?

(d) What is the status of any discussions/efforts to close NGS?

(e) What are the pros and cons of closing NGS?

(f) What analyses has TEP undertaken to determine if closing NGS is in the public interest?

(g) What will be the effect of closing NGS upon the rates that TEP's ratepayers are required to bear?

(h) What will be the effect of closing NGS upon the reliability of the electric grid, both in TEP's service territory and throughout the state?

(i) Are there other issues surrounding the potential closure of NGS that have a substantial bearing upon the public interest?

88. In its report, TEP should include any other information that TEP believes will be relevant to the Commission's full consideration of the issues surrounding NGS' closure.

89. After TEP has filed its report, our Hearing Division will issue a procedural order to undertake a proceeding on these issues, to provide an opportunity for other entities to intervene, to establish a schedule for pre-filing testimony, and to set a date for a hearing.

90. In this proceeding, TEP will submit its report as evidence. TEP may also submit any additional evidence that it would like us to consider.

91. We undertake this proceeding to ensure that we will have a full understanding of the rate and reliability impacts that this potential plant closure would cause for Arizona's ratepayers.

CONCLUSIONS OF LAW

1. TEP is an Arizona public service corporation within the meaning of Article XV, Section 2 of the Arizona Constitution.

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

3. Notice of the Rate Case Application and hearing was provided as required by law.

4. TEP's FVRB is $2,839,115,716.

5. A FVROR of 5.35 percent results in just and reasonable rates.

6. Adopting the Settlement Agreement, as modified and discussed herein, is in the public interest.

7. Rates and charges that conform to the findings herein are in the public interest.

ORDER

IT IS THEREFORE ORDERED that the Settlement Agreement dated August 15, 2016, 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, as soon as possible, but no later than February 28, 2017, revised schedules of rates and charges including an optional rate for LGS customers as discussed in Finding of Fact No. 60 that does not include a demand ratchet mechanism, consistent with the findings herein.

IT IS FURTHER ORDERED that the revised schedules of rates and charges shall be effective for all service rendered on the date Tucson Electric Power Company files its revised schedule of rates and charges, but no later than March 1, 2017.

IT IS FURTHER ORDERED that the default status of the TOU rate will not take effect until Tucson Electric Power Company files a notice with Docket Control that it has completed the necessary revisions to its billing systems, but the default must take effect no later than January 1, 2018.

IT IS FURTHER ORDERED that Tucson Electric Power shall review individual bill impacts for those frozen Lifeline customers identified by Staff as being particularly susceptible to unreasonable impacts, and if any of these frozen Lifeline customers would see impacts greater than 12 percent of their average annual monthly bill, Tucson Electric Power shall either increase the discount for these customers to fall within the guideline or keep these customers on their current frozen rate.

IT IS FURTHER ORDERED that within 12 months of the effective date of this Order, Tucson Electric Power Company shall file a Plan of Administration that details how the additional revenues it recovers as a result of the step-down mechanism we adopt for the gradual elimination of the governmental discount will be returned to other customers, and in its next rate case, shall provide testimony on the reasons for the governmental discount and whether or not its continuation is in the public interest.

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

IT IS FURTHER ORDERED that within 90 days of the effective date of this Decision, Tucson Electric Power Company shall file for Staff review and Commission approval, a detailed transition plan for the MGS Class that will include how Tucson Electric Power Company will communicate with affected customers, what demand information will be made available, and how it will be accessed, as well as possible training or education modules and a plan for transitioning existing SGS customers whose increased consumption in the future would qualify them for the MGS Class, and the process to transition MGS customers to the LGS Class.

IT IS FURTHER ORDERED that Staff shall prepare a recommendation on the transition plan for Commission approval within 90 days of its submission, and that the transitional two-part MGS rates shall remain in effect for 12 months following Commission approval the transition plan.

IT IS FURTHER ORDERED that DG systems that have filed for interconnection to Tucson Electric Power Company's distribution system prior to the effective date of the Decision in Phase 2 shall be considered to be fully grandfathered and continue to utilize currently implemented DG-related rate design and net metering for a period of 20 years from the date the DG system is interconnected, except that DG customers who file for interconne3ction after the effective date of this Decision shall be subject to the DG meter charges approved herein. Existing customers with DG systems will be subject to currently-existing rules and regulations impacting DG. Current commercial DG customers who will be transferred to the MGS Class or LGS Class shall be grandfathered on the MGS Class transition two-part rate design, subject to currently-existing rules and regulations impacting DG, with an option to adopt the MGS or LGS three-part rates.

IT IS FURTHER ORDERED that the record in this matter shall remain open for eighteen months after the effective date of this Decision in order that the Commission can address any unintended consequences resulting from the rate designs approved herein.

IT IS FURTHER ORDERED that Tucson Electric Power Company shall file within 120 days of the effective date of this Decision, a proposal to provide information to customers on the ratepayer costs of major energy resources via the web and a plan for communicating with customers about access to the data.

IT IS FURTHER ORDERED that Tucson Electric Power Company's Prepaid Energy Service shall be approved as a pilot program as recommended by Staff.

IT IS FURTHER ORDERED that Tucson Electric Power Company shall explore the development of an enhanced customer education, information and feedback program that can be made available to all residential customers to manage and reduce their energy bills, and to discuss its efforts in its next EE Implementation Plan.

IT IS FURTHER ORDERED that Tucson Meadows LLC shall be allowed to take service under the proposed GS-M-F tariff.

IT IS FURTHER ORDERED that the RPS Credit Option is hereby approved during the interim period from the effective date of this Order until a final determination in Phase 2 on whether the option remains reasonable.

IT IS FURTHER ORDERED that new Residential and SGS DG customers who submit applications for interconnection after the effect date of this Order shall be subject to a charge for the incremental cost of their bidirectional meter of $2.05 for Residential customers and $0.35 for SGS customers, but may choose to pay a one-time charge of $142.95 for Residential customers and $23.74 for SGS customers.

IT IS FURTHER ORDERED that the RPS Credit option and the second meter charge will be reviewed, and may be subject to modification, in Phase 2 of this proceeding.

IT IS FURTHER ORDERED that the final version of Tucson Electric Power Company's Rules and Regulations as revised by Staff and discussed herein are hereby approved.

IT IS FURTHER ORDERED that the LFCR is revised to include any lost fixed cost revenues resulting from must run generation assets, to increase the cap to 2 percent, and to eliminate the fixed charge option. Tucson Electric Power Company shall submit a revised Plan of Administration for the LFCR to reflect these modifications within 60 days of the effective date of this Decision.

IT IS FURTHER ORDERED that the cap on the Environmental Compliance Adjustor is increased to 0.5 percent.

IT IS FURTHER ORDERED that Tucson Electric Power Company and Staff shall address a uniform methodology for assessing the DSM surcharge in Tucson Electric Power Company's next application for a DSM Surcharge reset.

IT IS FURTHER ORDERED that Tucson Electric Power Company shall make its best effort to increase the peak demand reductions (MW) from EE programs in 2017 by 10 percent compared to the reported 2016 peak demand reductions form EE programs. Such programs must consider advanced technologies that can reduce or manage peak demand in addition to reducing energy use, such as wireless thermostats, energy management systems, and controls, many of which were highlighted during the Commission's technology workshops.

IT IS FURTHER ORDERED that Tucson Electric Power Company shall make its best effort to increase the peak demand reduction capability (MW) from DR and load management programs (not including Time-of-Use or other rates) in 2017 by 15 percent compared to the reported 2016 peak demand reductions from DR and load management programs. Such programs must consider facilitating energy storage technology.

IT IS FURTHER ORDERED that Tucson Electric Power Company, in its 2018 DSM Implementation Plan, increase the peak demand reductions (MW) from EE programs in 2018 and increase the peak demand reduction capability (MW) from DR and load management programs (not including Time-of-Use or other rates) in 2018 compared to the reported 2016 peak demand reductions form DR and load management programs. Such programs must consider facilitating energy storage and other advanced technologies.

IT IS FURTHER ORDERED that Tucson Electric Power Company, in its future DSM Implementation Plans, further increase the focus on peak demand reductions (MW) from EE, DR, storage, and load management programs that reduce customer energy demand during the period of system peak demand.

IT IS FURTHER ORDERED that Tucson Electric Power Company shall propose to the Commission, for approval, a residential or feeder level DR or load management program with a budget of $1.3 million which may be funded using unspent DSMAC collections, that facilitates energy storage technology, as discussed herein, within 120 days of the effective date of this Order.

IT IS FURTHER ORDERED that Tucson Electric Power Company, in its 2018 DSM Plan shall include the energy storage technology program, as discussed herein, with a budget of $1.3 million.

IT IS FURTHER ORDERED that Tucson Electric Power Company shall report the benefit-cost results of the energy storage technology program and of each energy storage measure as part of its regular reporting process for DSM. Given the developing nature of this energy storage technology program, the Commission will waive its normal benefit-cost threshold and revisit the program and measures in the Company's 2019 DSM Plan.

IT IS FURTHER ORDERED that within 60 days of the effective date of this Decision, Tucson Electric Power Company shall file a Plan of Administration for its REST adjustor that incorporates all existing pertinent Commission decisions, and is consistent with the Plan of Administration filed for UNS Electric, Inc.

IT IS FURTHER ORDERED that Tucson Electric Power Company shall file a report in its IRP docket by April 1, 2017, that addresses the issues surrounding the potential closure of the Navajo Generating Station discussed herein. Following the filing of the report, the Hearing Division will issue a procedural order to undertake a proceeding on these issues, to provide an opportunity for other entities to intervene, to establish a schedule for pre-filing testimony, and to set a date for a hearing.

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IT IS FURTHER ORDERED that Tucson Electric Power Company shall be relieved from further compliance filings associated with those prior Commission orders or rules as identified and discussed herein.

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

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN FORESE   COMMISSIONER DUNN

COMMISSIONER TOBIN   COMMISSIONER LITTLE   COMMISSIONER BURNS

IN WITNESS WHEREOF, I, TED VOGT, 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 24th day of February 2017.

TED VOGT
EXECUTIVE DIRECTOR

DISSENT ____________________

DISSENT ____________________

JR/rt

DECISION NO. 75975

SERVICE LIST FOR: TUCSON ELECTRIC POWER COMPANY

DOCKET NOS.: E-01933A-15-0239 and E-01933A-15-0322

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EXHIBIT A

TUCSON ELECTRIC POWER COMPANY

DOCKET NOS. E-01933A-15-0322 AND E-01933A-15-0239

SETTLEMENT AGREEMENT
REGARDING REVENUE REQUIREMENT

AUGUST 15, 2016

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SETTLEMENT AGREEMENT REGARDING REVENUE REQUIREMENT IN DOCKET NOS. E-01933-A-15-0322 AND E-01933A-15-0239 TUCSON ELECTRIC POWER COMPANY'S REQUEST FOR RATE ADJUSTMENT

The purpose of this Settlement Agreement ("Agreement") is to settle disputed issues related to the revenue requirement in Docket No. E-01933-A-15-0322 and E-01933A-15-0239, 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")
Freeport Minerals Corporation ("Freeport Minerals")
Arizonans for Electric Choice and Competition ("AECC")
Arizona Investment Council ("AIC")
Western Resource Advocates ("WRA")
Wal-Mart Stores, Inc. and Sam's West, Inc. (collectively "Wal-Mart")
Noble Americas Energy Solutions, LLC ("Noble Solutions")
The Kroger Co. ("Kroger")
Sierra Club

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 a rate application with the Arizona Corporation Commission ("Commission") in Docket No. E-01933-A-15-0322 on November 5, 2015. The application was found to be sufficient on December 7, 2015. The rate case docket was subsequently consolidated with Docket No. E-01933-A-15-0239 ("TEP 2016 REST Plan docket") on April 6, 2016.

1.2 The Commission granted applications for intervention filed by RUCO, Freeport-Minerals and AECC (collectively "AECC"), Arizona Public Service Company, Southwest Energy Efficiency Project ("SWEEP"), IBEW Local 1116 ("IBEW"), Sierra Club, The United States Department of Defense and all Other Federal Executive Agencies ("DOD"), AIC, Arizona Community Action Association, Vote Solar, Arizona Solar Energy Industries Association, Energy Freedom Coalition of America, Kevin Koch, Noble Solutions, SOLON Corporation, Kroger, Wal-Mart, Western Resource Advocates, Arizona Competitive Power Alliance, Arizona Solar Deployment Alliance, Arizona Utility Ratepayer Alliance, Southern Arizona Homebuilders Association, Pima County, The Alliance for Solar Choice, Tucson Meadows, L.L.C., Bruce Plenk, and Bryan Lovitt (collectively "Parties").

1.3 Pursuant to the December 14, 2015 Procedural Order in this docket, the following parties filed direct testimony (except that related to rate design and cost of service) on June 3, 2016: Staff, RUCO, AECC, IBEW, SWEEP, DOD, WRA, Wal-Mart, and Sierra Club. On July 25, 2016, TEP filed rebuttal testimony.

1.4 Staff filed a Notice of Settlement Discussions regarding revenue requirement only on July 28, 2016. Settlement discussions on revenue requirement took place on August 5, 2016. The settlement discussions were open, transparent, and inclusive of all Parties to this Docket who desired to participate in person or telephonically. All Parties to this Docket were notified of the settlement meeting, were encouraged to participate in the negotiations, and were provided with an opportunity to participate.

1.5 The terms of this Agreement are just, reasonable, fair, and in the public interest in that they, among other things, establish a just and reasonable revenue requirement for TEP and its customers; promote the convenience, comfort and safety, and the preservation of health, of the employees and patrons of TEP; resolve revenue requirement issues arising from this Docket; and avoid additional litigation expense relating to the revenue requirement issues in this proceeding.

1.6 The Signatories believe that this Agreement balances the interests of both TEP and its customers.

1.7 The Signatories request that the Commission adopt this Agreement such that the revenue requirement provisions contained herein may become effective following the issuance of a final Order in this Docket by the Commission.

TERMS AND CONDITIONS

II. RATE INCREASE

2.1 TEP shall receive a non-fuel base rate increase of $81,500,000 over adjusted test-year non-fuel retail revenues, reflecting a total non-fuel revenue requirement of $714,022,900. Attachment A sets forth the adjustments to TEP's initial request for a non-fuel base rate increase of $109,500,000 that results in the settlement amount.

2.2 TEP's average base fuel rate shall be set to $0.0325559 to recover a total of $289,147,243 in base fuel revenues. Present rates include an average base fuel rate of $0.032335.

2.3 TEP's total revenue requirement shall be $1,003,170,143.

2.4 Of the allowed non-fuel base rate increase, $15,243,913 is contingent upon TEP purchasing a 50.5% share of Unit 1 of Springerville Generating Station ("SGS Unit 1). The portion of the rate increase is not effective until after the purchase has been completed and a final Order has been issued in this docket. This amount was originally proposed by TEP to be collected through the PPFAC. As such, recovery of this amount through non-fuel rates represents a revenue neutral change to the agreed upon revenue requirement.

2.5 The Company's jurisdictional fair value rate base ("FVRB") used to establish the rates agreed to herein is $2,843,985,854, representing an average of the original cost rate base ("OCRB") of $2,045,203,460 and the replacement cost new less depreciation rate base ("RCND") of $3,633,027,972.

III. COST OF CAPITAL

3.1 The actual test year capital structure comprised of 49.97% long-term debt and 50.03% common equity shall be adopted.

3.2 A return on common equity of 9.75% and an embedded cost of long-term debt of 4.32%, resulting in a weighted average cost of capital of 7.04%.

3.3 A fair value rate of return of 5.34%, which includes a rate of return on the fair value increment of rate base of 1.00%, shall be adopted.

3.4 The provisions set forth herein regarding the quantification of cost of capital, fair value rate base, fair value rate of return, and the non-fuel 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.

IV. DEPRECIATION AND AMORTIZATION

4.1 The depreciation and amortization rates proposed by TEP in its rebuttal testimony shall be adopted, except (i) that the rates for San Juan Generating Station shall be adjusted to reflect a depreciable life of TEP's total investment, including the Balanced Draft project, at San Juan Unit 1 of six (6) years; (ii) $90 million of excess distribution reserves will be transferred to San Juan Unit 1 and (iii) a change to depreciation rates on TEP's distribution plant to offset the change in depreciation expense for San Juan Unit 1. TEP will file, with its testimony in support of the Settlement, schedules setting forth the applicable depreciation and amortization rates, including those for San Juan Unit 1.

V. SPRINGERVILLE UNIT 1

5.1 TEP shall file a notice in this Docket upon the completion of its pending purchase of a 50.5% interest in SGS Unit 1. If the purchase is completed after the effective date of new rates, the $15,243, 913 million of contingent non-fuel base rate relief will be made effective within 30 days of the notice date.

5.2 TEP shall not request rate base treatment of the purchase price paid for the 50.5% share of SGS Unit 1 until its next general rate case.

5.3 The leasehold improvements associated with a 50.5% share of SGS Unit 1 shall be included in OCRB at the net book value ("NBV") as of December 31, 2016. Amortization of these plant investments will continue as approved in TEP's last rate case (Decision No. 73912 (June 27, 2013)).

VI. ADDITIONAL SETTLEMENT PROVISIONS

6.1 TEP shall write down the NBV of its headquarters building by $5 million resulting in a $5 million reduction to the total Company OCRB within 30 days following the issuance of a final Order in this docket. The provisions of Section

8.3 notwithstanding, the Signatories agree that they will not seek alternative rate treatment, or additional write-downs of the headquarters building, in future rate proceedings.

6.2 TEP's OCRB shall include post-test year plant that is verified and in service as of June 30, 2016 of $49.6 million, and post-test year renewable generation plant of $4.8 million.

6.3 Certain issues related to the Company's rate application, including but not limited to rate design, the Lost Fixed Cost Recovery mechanism, the Buy-Through Tariff, the inclusion of Energy Efficiency Program Funding in base rates, the Purchase Power Fuel Adjustor, net metering remain unresolved by this Agreement, and the Signatories agree to present their respective positions in the hearing scheduled in this proceeding. This provision is not intended to limit any Signatory's ability to present its position on these unresolved issues.

VII. COMMISSION EVALUATION OF PROPOSED SETTLEMENT

7.1 All currently filed testimony and exhibits regarding revenue requirement shall be offered into the Commission's record as evidence.

7.2 The Signatories shall file testimony in support of the Agreement as part of their Surrebuttal or Rejoinder testimonies or as otherwise provided by Procedural Order modifying the procedural schedule.

7.3 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.

7.4 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.

7.5 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.

VIII. MISCELLANEOUS PROVISIONS

8.1 This case has participants with widely diverse revenue requirement positions. To achieve consensus for the settlement of revenue requirement issues, 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 the public interest and with long-term interests of the undersigned parties as to issues or matters resolved by this Settlement Agreement. 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.

8.2 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.

8.3 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.

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

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

8.6 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 7.5 above, if the Commission adopts an order approving all material terms of the Agreement, the Signatories will support and defend, or agree not to oppose, the Commission's order before any court or regulatory agency in which it may be at issue.

8.7 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 [signature]

Title Director, Utilities

Date 8/15/16

TUCSON ELECTRIC POWER COMPANY

By____________________

Title____________________

Date____________________

8.7 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 CEO

Date 8/15/16

Signatory to August 15, 2016 Tucson Electric Power Company Revenue Requirement Settlement Agreement in Docket Nos. E-01933A-15-0239 and E-01933A-15-0322.

RESIDENTIAL UTILITY CONSUMER OFFICE

By [signature]

Title Director

Date 8/15/16

Signatory to August 15, 2016 Tucson Electric Power Company Revenue Requirement Settlement Agreement in Docket Nos. E-01933A-15-0239 and E-01933A-15-0322.

ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION

By ____________________

Title President

Date 8/15/16

Signatory to August 15, 2016 Tucson Electric Power Company Revenue Requirement Settlement Agreement in Docket Nos. E-01933A-15-0239 and E-01933A-15-0322.

FREEPORT MINERALS CORPORATION

By Michael McElrath

Title Director Energy Services

Date August 15, 2016

Signatory to August 15, 2016 Tucson Electric Power Company Revenue Requirement Settlement Agreement in Docket Nos. E-01933A-15-0239 and E-01933A-15-0322.

SIERRA CLUB

By Travis Ritchie

Title Staff Attorney

Date 8-15-2016

Signatory to August 15, 2016 Tucson Electric Power Company Revenue Requirement Settlement Agreement in Docket Nos. E-01933A-15-0239 and E-01933A-15-0322.

WESTERN RESOURCE ADVOCATES

By ____________________

Title Attorney for WRA

Date 8/12/16

Signatory to August 15, 2016 Tucson Electric Power Company Revenue Requirement Settlement Agreement in Docket Nos. E-01933A-15-0239 and E-01933A-15-0322.

NOBLE AMERICAS ENERGY SOLUTIONS, LLC

By Lawrence V. Robertson, Jr.

Title Attorney

Date August 15, 2016

Signatory to August 15, 2016 Tucson Electric Power Company Revenue Requirement Settlement Agreement in Docket Nos. E-01933A-15-0239 and E-01933A-15-0322.

THE KROGER CO.

By [signature]

Title Attorney for Kroger Co.

Date 8/15/16

Signatory to August 15, 2016 Tucson Electric Power Company Revenue Requirement Settlement Agreement in Docket Nos. E-01933A-15-0239 and E-01933A-15-0322.

THE KROGER CO.

By ______

Title Attorney for Kroger Co.

Date 8/15/16

Signatory to August 15, 2016 Tucson Electric Power Company Revenue Requirement Settlement Agreement in Docket Nos. E-01933A-15-0239 and E-01933A-15-0322.

WAL-MART STORES, INC. and SAM'S WEST, INC.

By Scott S Chapell

Title Counsel

Date August 15, 2016

Signatory to August 15, 2016 Tucson Electric Power Company Revenue Requirement Settlement Agreement in Docket Nos. E-01933A-15-0239 and E-01933A-15-0322.

ARIZONA INVESTMENT COUNCIL

By ____________

Title President & CEO

Date 8/15/2016

ATTACHMENT A
TO REVENUE REQUIRMENT SETTLEMENT AGREEMENT
AUGUST 15, 2015

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
ATTACHMENT A TO SETTLEMENT AGREEMENT

	TEP As Filed	TEP Rebuttal	Settlement	Total Difference	Explanation of TEP Revisions
Original Cost Rate Base - Unadjusted	$2,108,583,243	$2,108,583,243	$2,108,583,243	-	
Rate Base Adjustments					
Jurisdictional Allocation (Demand and Energy)	-	(32,996,491)	(32 996,491)	(32,996,491)	Impact of change to jurisdictional allocations except for impacts to rate base adjustments listed below.
SGS CHF	(41,966,722)	(41,239,083)	(41,239,083)	727,640	Impact of change to jurisdictional allocations
Fortis Merger Rate Base Adjustment	(522,398)	(517,560)	(517,560)	4,838	Impact of change to jurisdictional allocations
Asset Retirement Obligation	-	-	-	-	
Post Test Year Plant	51,782,029	51,003,979	49,627 152	(2,154,877)	Settlement Position - Exclude plant not in service prior to June 2016
Post Test Year Plant - Renewables	20,794,266	20,433,724	4,815,398	(15,978,868)	Settlement Position - Exclude plant not in service prior to June 2016
Delayed Unitization	13,237.543	13,118,186	13,118,186	(119,357)	Impact of change to jurisdictional allocations
Accumulated Deferred Investment Tax Credit (ITC)	30,341,626	30,341,626	30,341,626	-	
Accumulated Deferred Income Taxes	(58,308,686)	(57,662,694)	(53,460,485)	4,848,201	Impact of change to jurisdictional allocations and conforming changes
ADIT - Extension of Bonus Depreciation	-	(12,672,205)	(12,673,409)	(12,673,409)	ADIT related to extension of bonus depreciation
San Juan Unit 2	-	(0)	-	-	
Sundt Coal Handling facilities	(19.120)	(18,789)	(18,789)	331	Impact of change to jurisdictional allocations
SGS Unit 1 Lease Equity (related to 14.1% acquisition in 2006)	6,855,471	6,736,607	6,736,607	(118,864)	Impact of change to jurisdictional allocations
SGS Leashold Amortization Roll Forward	-	-	(3,582,976)	(3,582,976)	Settlement Position - Reflecting the roll-forward of accumulated amortization for leasehold improvments linked to SGS Unit 1 50.5%
Sundt & San Juan M&S	1,225,594	1,956,711	1,956,711	731,117	Increase is do to the revision of obsolete inventory at Sundt
Head Quarters	-	-	(4,322,455)	(4,322,455)	Settlement Position - $5M Write-down of TEP's investment in the HQ building
Working Capital	(27,325,154)	(20,740,139)	(21,164,215)	6,160,939	Impact of changes to pro forma adjustments.
Accumulated Depreciation adj and LTI	-	-	-	-	
Total Adjustments	(3,905,553)	(42,258,127)	(63,379,783)	(59,474,230)	

TUCSON ELECTRIC POWER					
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT					
TEST YEAR ENDED JUNE 30, 2015					
ACC JURISDICTION					
ATTACHMENT A TO SETTLEMENT AGREEMENT					
	TEP As Filed	TEP Rebuttal	Settlement	Total Difference	Explanation of TEP Revisions
Pro Forma OCRB	2,104,677,690	2,066,327,116	2,045,203,460		
Proposed Rate of Return	7.34%	7.16%	7.04%		
Required Operating Income OCRB	$154,416,180	$147,964,232	$143,913,380		
Fair Value Increment of Rate Base	$808,601,055	791,549,067	798,782,394		
Fair Value Rate Base (FVRB)	$2,913,278,745	$2,857,876,183	$2,843,985,854		
Proposed FVROR	5.69%	5.57%	5.34%		
Required Operating Income on FVRB	165,898,315	159,224,227	151,901,204		
Implied ROR on Fair Value Increment of Rate Base	1.42%	1.42%	1.00%		
Original Operating Income - Unadjusted	$318,271,141	$318,271,141	$318,271,141		
Operating Income Adjustments					
Operating Revenue Adjustments					
Lost Fixed Cost Revenue	(10,719,946)	(10,719,946)	(10,719,946)	-	
Revenue Reduction Industrial Customer Curtailment			(4,579,770)	(4,579,770)	This Reflects the impact of a large Industrial Customer Curtailment.
Environmental Cost Adjustor	(1,260,631)	(1,260,631)	(1,260,631)	-	
REST and DSM	(48,370,058)	(48,370,058)	(48,370,058)	-	
Non-Retail & Non Recurring Revenue	(112,150)	(112,150)	(112,150)	-	
Springerville Units 3 & 4	(111,813,089)	(111,813,089)	(111,813,089)	-	
Power Supply Management	(1,099,586)	(1,099,586)	(1,099,586)	-	
Customer, Weather and Recalculation of Unbilled Revenue	(4,791,733)	(4,791,733)	(4,791,733)	-	

TUCSON ELECTRIC POWER

COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT

TEST YEAR ENDED JUNE 30, 2015

ACC JURISDICTION

ATTACHMENT A TO SETTLEMENT AGREEMENT

	TEP As Filed	TEP Rebuttal	Settlement	Total Difference	Explanation of TEP Revisions
Base Cost of Fuel & Purchased Power	(17,815,595)	(32,594,041)	(32,594,041)	(14,778,446)	Variance is due to a decrease in kWh sales (from 9,021M to 8,881M) and a decrease in the proposed PPFAC rate (from 3.3692 to 3.2559).
Miscellaneous Service Revenue	284,370	284,370	284,370	-	
TEP Headquarters - Retail Space	250,000	250,000	250,000	-	
Total Adjustments to Operating Revenues	(195,448,418)	(210,226,864)	(214,806,634)	(19,358,216)	
Operating Expense Adjustments					
Jurisdictional Allocation (Demand and Energy)	-	(2,619,840)	(2,619,840)	(2,619,840)	Impact of change to jurisdictional allocations except for impacts to operating expense adjustments listed below.
REST and DSM	(19,891,996)	(19,769,956)	(19,769,956)	122,040	Impact of change to jurisdictional allocations
Non-Retail & Non Recurring Revenue	(1,696,421)	(1,663,540)	(1,663,540)	32,881	Impact of change to jurisdictional allocations
Springerville Units 3 & 4	(84,382,546)	(83,129,337)	(83,129,337)	1,253,210	Impact of change to jurisdictional allocations
Sales of SO2 Allowances	47	47	47	-	
Sales for Resale	(162,821,057)	(162,821,057)	(162,821,057)	-	
Power Supply Management	(278,075)	(276,646)	(276,646)	1,429	Impact of change to jurisdictional allocations
Base Cost of Fuel & Purchased Power	226,811,827	212,033,380	212,033,380	(14,778,447)	See explanation in Operating Revenues section.
Gila River O&M	6,130,964	6,024,663	6,024,663	(106,301)	Impact of change to jurisdictional allocations
Springerville Unit 1	(11,558,130)	(11,384,664)	(11,384,664)	173,466	Impact of change to jurisdictional allocations
SGS Unit 1 Non Fuel O&M (50.5% Share)	-	15,243,913	15,243,913	15,243,913	Addition of non-fuel operating costs associated with the 50.5% share of SGS Unit 1.
Overhaul & Outage Normalization	5,176,492	5,844,715	4,889,841	(286,651)	Settlement Position - To reflect a six year historical average outage expense.
Payroll Expense	2,264,794	2,250,757	1,657,361	(607,433)	Settlement Position - To exclude the 2017 2% payroll increase related to Non-Classified employees.
Payroll Tax Expense	151,051	151,051	111,227	(39,824)	
Pension & Benefits	2,004,436	1,576,055	1,576,055	(428,381)	Removed SERP expense as proposed by Staff and RUCO.
Post-Retirement Benefits	1,339,160	1,339,160	1,339,160	-	

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
ATTACHMENT A TO SETTLEMENT AGREEMENT

	TEP As Filed	TEP Rebuttal	Settlement	Total Difference	Explanation of TEP Revisions
Short-Term Incentive Compensation	702,960	1,578,745	(1,932,314)	(2,635,274)	Settlement Position - To reflect a 50/50 sharing between company and rate payer.
Rate Case Expense	107,834	107,834	(15,231)	(123,065)	Settlement Position - To reflect $1M normalized over 4 years
Injuries and Damages	1,419	1,419	1,419	-	
Membership Dues	(212,696)	(212,690)	(212,690)	6	Impact of change to jurisdictional allocations
Bad Debt Expense	(149,199)	(149,199)	(149,199)	-	
San Juan Unit 2 Direct Operating Cost	(3,921,687)	(3,869,457)	(3,869,457)	52,230	Impact of change to jurisdictional allocations
Long Term Incentive Compensation	880,967	-	-	(880,967)	Remove long term incentive compensation as proposed by Staff.
Depr. & Amort. Expense	9,253,715	1,542,840	1,542,839	(7,710,876)	Decrease is due to removal of 2% inflation for dismantlement costs, and a -5% future net salvage value for distribution assets.
Post Test Year Plant Depreciation and Amortization	-	4,568,106	4,099,163	4,099,163	Settlement Position - To reflect the impact of Post Test year plant exclusions.
Sundt & San Juan M&S	408,531	652,237	652,237	243,706	Increase is due to an increase in obsolete Sundt coal handling inventory.
Property Tax Expense	3,119,696	3,119,770	3,119,770	74	Impact of change to jurisdictional allocations
Asset Retirement Obligation	(393,590)	(386,765)	(386,765)	6,825	Impact of change to jurisdictional allocations
SGS Common Facilities Lease	(1,195,980)	(1,175,244)	(1,175,244)	20,736	Impact of change to jurisdictional allocations
San Juan Unit 1 SCNR O&M	955,223	938,661	938,661	(16,562)	Impact of change to jurisdictional allocations
Fortis Merger Operating Income Adjustment	(31,176,174)	(31,176,174)	(31,176,174)	-	
Lime Expense		(1,612,486)	(1,612,486)	(1,612,486)	Company removed lime expense included in test year related to our jointly owned facility. These costs are recovered in base cost of fuel
TEP Headquarters - Write Down	-	-	(109,155)	(109,155)	Settlement Position - $5M Write-down of TEP's investment in the HQ building
Outside Legal Expense			(1,124,730)	(1,124,730)	Settlement Position - To reflect the removal of litigation cost with Alterna.
Credit Card Processing Fees	3,475,500	-	-	(3,475,500)	Removed credit card processing fees as proposed by Staff and RUCO.
Income Tax Expense	(16,130,352)	(19,049,439)	(21,370,950)	(5,240,598)	Conforming changes

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
ATTACHMENT A TO SETTLEMENT AGREEMENT

	TEP As Filed	TEP Rebuttal	Settlement	Total Difference	Explanation of TEP Revisions
Transmission Expense Adjustment	95,464,952	93,719,409	93,719,409	(1,745,543)	Decrease in transmission expense reflects the impact of a usage reduction related to one of the Company's largest customers.
D&O Insurance	-	(21,105)	(21,105)	(21,105)	Accepted 50/50 sharing as proposed by RUCO and Staff.
Lobbying, Employee Recognition, Spot Award, Wellness - New	-	-		-	
Severance Pay	-	(329,665)	(329,665)	(329,665)	Removed severance pay as proposed by RUCO.
Total Adjustments to Operating Expense	24,441,665	10,845,501	1,798,941	(22,642,724)	
Total Net Adjustments	(219,890,083)	(221,072,365)	(216,605,575)		
Adjusted Operating Income	$98,381,058	$97,198,776	$101,665,566		
Operating Income Deficiency	$67,517,257	$62,025,451	$50,235,638		
Gross Revenue Conversion Factor	1.6223	1.6223	1.6223		
Increase in Gross Revenue Requirement	$109,534,118	$100,624,690	$81,497,921		

DOCKET NO. E-01933A-15-0239 ET AL.

DECISION NO. 75975