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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE, Chairman
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

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

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NOTICE OF FILING

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the Surrebuttal Testimony and Settlement Testimony of Robert Mease, Jeffrey Michlik, Frank Radigan and Lon Huber, in the above referenced matter.

RESPECTFULLY SUBMITTED this 25th day of August, 2016.

Arizona Corporation Commission
DOCKETED
AUG 25 2016
DOCKETED BY

Daniel W. Pozefsky
Chief Counsel

AN ORIGINAL AND THIRTEEN COPIES
of the foregoing filed this 25th day
of August, 2016 with:

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

COPIES of the foregoing hand delivered/
mailed this 25th day of August, 2016 to:

Michael W. Patten
Jason D. Gellman
Snell & Wilmer LLP
One Arizona Center
400 E. Van Buren Street
Phoenix, AZ 85004
mpatten@swlaw.com
bcarroll@tep.com
jhoward@swlaw.com
docket@swlaw.com
Consented to Service by Email

Barbara La Wall
Charles Wesselhoft
Pima County Attorneys Office
32 N. Stone Ave., Suite 2100
Tucson, AZ 85701
Charles.Wesselhoft@pcao.pima.gov
Consented to Service by Email

C. Webb Crockett
Patrick J. Black
Fennemore Craig, P.C.
2394 E. Camelback Rd, Suite 600
Phoenix, AZ 85016
wcrockett@fclaw.com
pblack@fclaw.com
Consented to Service by Email

Kevin Higgins
Energy Strategies, LLC
215 South State Street, Suite 200
Salt Lake City, Utah 84111

Nicholas J. Enoch
Jarrett J. Haskovek
Emily A. Tornabene
Lubin & Enoch, PC
349 N. Fourth Ave.
Phoenix, AZ 85003
Attorneys for IBEW Local 1116

Lawrence V. Robertson, Jr.
P.O. Box 1448
Tubac, AZ 85646
Attorney for Noble Solutions and SAHBA
tubaclawyer@aol.com
Consented to Service by Email

Meghan H. Grabel
Osborn Maledon, PA
2929 N. Central Ave., Suite 2100
Phoenix, AZ 85012
Attorneys for AIC
mgrabel@omlaw.com
Consented to Service by Email

Gary Yaquinto
Arizona Investment Council
2100 N. Central Ave., Suite 210
Phoenix, AZ 85004
gyaquinto@arizonaaic.org
Consented to Service by Email

Court S. Rich
Loren Ungar
Rose Law Group, PC
7144 E. Stetson Dr., Suite 300
Scottsdale, AZ 85251
Attorney for TASC & EFCA
crich@roselawgroup.com
Consented to Service by Email

Timothy M. Hogan
Arizona Center for Law in the Public Interest
514 W. Roosevelt St.
Phoenix, AZ 85003
Attorney for Vote Solar, ACAA, WRA and SWEEP
thogan@aclpi.org
Consented to Service by Email

Rick Gilliam
The Vote Solar Initiative
1120 Pearl St., Suite 200
Boulder, Co 80302
rick@votesolar.org
Consented to Service by Email

Briana Kobor
Vote Solar
360 22nd St., Suite 730
Oakland, CA 94612
briana@votesolar.org
Consented to Service by Email

Michael Hiatt
Katie Dittelberger
Earthjustice Rocky Mountain Office
633 17th St., Suite 1600
Denver, CO 80202
mhiatt@earthjustice.org
kdittelberger@earthjustice.org
Consented to Service by Email

Craig A. Marks
Craig A. Marks, PLC
10645 N. Tatum Blvd., Suite 200-676
Phoenix, AZ 85028
Craig.Marks@azbar.org
Consented to Service by Email

Pat Quinn
Arizona Utility Ratepayer Alliance
5521 East Cholla Street
Scottsdale, Arizona 85254

Thomas A. Loquvam
Pinnacle West Capital Corp.
P.O. Box 53999, MS 8695
Phoenix, AZ 85072
Thomas.Loquvam@pinnaclewest.com
Consented to Service by Email

Kerri A. Carnes
Arizona Public Service Company
P.O. Box 53072, MS 9712
Phoenix, AZ 85072
Kerri.Carnes@aps.com
Consented to Service by Email

Travis Ritchie
Sierra Club Environmental Law Program
85 Second St., 2nd Floor
San Francisco, CA 94105
Travis.ritchie@sierraclub.org
Consented to Service by Email

Scott Wakefield
Hienton & Curry, PLLC
5045 N. 12h St., Suite 110
Phoenix, AZ 85014
Attorney for Wal-Mart

Steven W. Chriss
Wal-Mart Stores, Inc.
2011 S.E. 10th St.
Bentonville, AR 72716

Ken Wilson
Western Resource Advocates
2260 Baseline Rd, Suite 200
Boulder, CO 80302

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

Ellen Zuckerman
SWEEP
1627 Oak View Ave.
Kensington, CA 94707

Cynthia Zwick
Kevin Hengehold
Arizona Community Action Assoc.
2700 N. 3rd St., Suite 3040
Phoenix, AZ 85004

Bryan Lovitt
3301 W. Cinnamon Dr.
Tucson, AZ 85741

Kevin M. Koch
P.O. Box 42103
Tucson, AZ 85733

Karen White
139 Barnes Dr., Suite 1
Tyndall Air Force Base, FL 32401
Karen.white.13@us.af.mil
Consented to Service by Email

Kyle J. Smith
9275 Gunston Rd, Suite 1300
JALS RL/IP
Fort Belvoir, VA 22060
Kyle.j.smith124.civ@mail.mil
Consented to Service by Email

Jeffrey W. Crockett
Crockett Law Group, PLLC
2198 E. Camelback Rd, Suite 305
Phoenix, AZ 85016

Bruce Plenk
2958 N. St. Augustine Pl
Tucson, AZ 85712
solarlawyeraz@gmail.com
Consented to Service by Email

Garry D. Hays
Law Offices of Garry D. Hays, PC
2198 E. Camelback Rd, Suite 305
Phoenix, AZ 85016

Camila Alarcon
Gammage & Burnham, PLC
Two N. Central Ave., 15th Floor
Phoenix, AZ 85004
Attorneys for SOLON Corp.

Michele L. Van Quathem
Law Offices of Michele Van Quathem, PLLC
7600 N. 15th St., Suite 150-30
Phoenix, AZ 85020
Attorneys for SOLON Corp.

Greg Patterson
Munger Chadwick
916 W. Adams, Suite 3
Phoenix, AZ 85007
Attorneys for AZ Competitive Power Alliance

Jeffrey Shinder
Constantine Cannon LLP
335 Madison Ave., 9th Floor
New York, NY 10017

Richard O. Levine
Constantine Cannon LLP
1001 Pennsylvania Ave., NW
Suite 1300 North
Washington, DC 20004

Kurt Boehm
Jody Kyler Cohn
Boehm, Kurtz & Lowry
36 E. Seventh St., Suite 1510
Cincinnati, OH 45202
Attorneys for The Kroger Co.

John William Moore, Jr.
Moore Benham & Beaver, PLC
7321 N. 16th St.
Phoenix, Arizona 85020
Attorney for Kroger

The Kroger Co.
Attn: Corporate Energy Manager (G09)
1014 Vine Street
Cincinnati, OH 45202

Stephen Baron
J. Kennedy & Associates
570 Colonial Park Dr., Suite 305
Roswell, GA 30075

Tom Harris
Arizona Solar Energy Industries Assoc.
2122 W. Lone Cactus Dr., Suite 2
Phoenix, Arizona 85027
Tom.Harris@AriSeia.org
Consented to Service by Email

Janice Alward
Legal Division
Arizona Corporation Commission
1200 W. Washington
Phoenix, Arizona 85007
rmitchell@azcc.gov
wvancleve@azcc.gov
cfitzsimmons@azcc.gov
legaldiv@azcc.gov
Consented to Service by Email

By Cheryl Fraulob
Cheryl Fraulob

TUCSON ELECTRIC POWER COMPANY

DOCKET NOS. W-01933A-15-0322

SURREBUTTAL TESTIMONY AND

SETTLEMENT TESTIMONY

OF

ROBERT MEASE

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

AUGUST 25, 2016

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EXECUTIVE SUMMARY

The Residential Utility Consumer Office's ("RUCO") has reviewed Tucson Electric Power Company's rebuttal testimony, and proposed Settlement Agreement in regards to its application for a permanent rate increase, filed with the Arizona Corporation Commission on November 5, 2015, and August 15, 2016, respectively, ("ACC" or "Commission") and RUCO recommends the following:

Capital Structure – RUCO recommended a capital structure consisting of 49.97% cost of long-term debt and 50.03% cost of common equity. The Company's and RUCO's recommended capital structure was adopted in the Settlement Agreement.

Cost of Debt – RUCO is recommending and the Company has agreed that the Commission adopt the Company's actual end of test year cost of long-term debt of 4.32 percent.

Cost of Equity Capital – RUCO recommended a cost of common equity of 9.20% in direct testimony compared to the Company's original request of 10.35%. RUCO accepted the 9.75% in final settlement as this has been the average authorized ROE's for State Jurisdictional Electric Utility Operations (Vertically Integrated) during years 2015 and 2016 as published by SNL Financial.

Original Cost Rate of Return – The Company has recommended and RUCO is in agreement that the ACC adopt a 7.04 percent weighted average cost of capital as the original cost rate of return ("OCROR") for TEP. RUCO's recommended rate of return represents the weighted cost of RUCO's recommended cost of common equity and cost of debt, subsequent to settlement discussions, and is 30 basis points lower than the 7.34 percent weighted average cost of capital originally proposed by the Company.

Fair Value Rate of Return – RUCO is in agreement that the Commission adopt a fair value rate of return ("FVROR") of 5.34 percent which includes a rate of return on the fair value increment of rate base of 1.00%.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My Name is Robert B. Mease. I am the Chief of Accounting and Rates for the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Have you previously provided testimony regarding this docket?

A. Yes. I filed testimony in this docket on June 3, 2016 specifically related to TEP's Capital Structure, Cost of Debt, Cost of Equity, Original Cost Rate of Return and Fair Value Rate of Return.

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony will address the settlement provisions as outlined in the Settlement Agreement as filed by the Company on August 15, 2016. RUCO believes that the terms as filed in the Settlement Agreement are just, reasonable, fair and in the public interest.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Please summarize the recommendations and adjustments that you will address in your surrebuttal testimony.

A. Based on the results of my analysis as well as final settlement discussions, I am making the following recommendations:

Capital Structure – RUCO recommended a capital structure consisting of 49.97% cost of long-term debt and 50.03% cost of common equity. The Company's and RUCO's recommended capital structure was adopted in the Settlement Agreement. The Company has no short-term debt.

Cost of Debt – RUCO is recommending that the Commission adopt the Company's actual end of test year cost of long-term debt of 4.32 percent.

Cost of Equity Capital – RUCO recommended a cost of common equity of 9.20% in direct testimony compared to the Company's original request of 10.35%. RUCO accepted the 9.75% in final settlement as this has been the average authorized ROE's for State Jurisdictional Electric Utility Operations (Vertically Integrated) during years 2015 and 2016 as published by SNL Financial.

Original Cost Rate of Return – RUCO is recommending that the ACC adopt a 7.04 percent weighted average cost of capital as the original cost rate of return ("OCROR") for TEP. RUCO's recommended rate of return represents the weighted cost of RUCO's recommended cost of common equity and cost of debt, subsequent to settlement discussions, and is 30 basis points lower than the 7.34 percent weighted average cost of capital originally proposed by the Company.

Fair Value Rate of Return – RUCO is recommending that the Commission adopt a fair value rate of return ("FVROR") of 5.34 percent which includes a rate of return on the fair value increment of rate base of 1.00%.

Q Why do you believe that RUCO's recommended 7.04 percent OCROR and 5.34 percent FVROR are appropriate rates of return for TEP to earn on its invested capital?

A. Both the OCROR and FVROR figures that have been agreed to by RUCO, TEP, and other intervening parties meet the criteria established in the landmark Supreme Court cases of <u>Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia</u> (262 U.S. 679, 1923) and <u>Federal Power Commission v. Hope Natural Gas Company</u> (320 U.S. 391, 1944).

Q. Does RUCO believe that their acceptance of the cost of equity and fair value adjustment in this case bounds RUCO to the same in rate cases going forward?

A. Absolutely not. If RUCO agrees with this position in this case it does not presuppose that RUCO will recommend or agree to this return on equity or fair value increment in future rate case applications.

Q. Does this conclude your testimony on TEP?

A. Yes, it does.

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. W-01933A-15-0322

SURREBUTTAL TESTIMONY AND

SETTLEMENT TESTIMONY

OF

JEFFREY MICHLIK

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

AUGUST 25, 2016

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ATTACHMENTS

EXECUTIVE SUMMARY

The Residential Utility Consumer Office ("RUCO") has reviewed the rebuttal testimony of Tucson Electric Power Company ("Company or TEP"), and the direct testimony of Commission Staff ("Staff") and the various interveners in this docket.

The testimony herein, discusses RUCO's settlement of issues related to the revenue requirement and issues that are still outstanding.

I. INTRODUCTION

Q. Please state your name for the record.

A. My name is Jeffrey M. Michlik.

Q. Have you previously filed testimony regarding this docket?

A. Yes, I have. I filed direct testimony in this docket on June 3, 2016.

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony will address the revenue requirement, and other issues.

Q. How is your surrebuttal testimony organized?

A. My surrebuttal testimony is presented in three sections. Section I provides an introduction. Section II addresses the settlement of the revenue requirement by several parties in this case, and Section III addresses other issues.

II. SETTLEMENT OF REVENUE REQUIREMENT

Q. Did the Company, Staff, RUCO and several other intervenors meet with the Company in settlement negotiations to try to narrow and settle issues relating to the revenue requirement in this case?

A. Yes. The parties in this proceeding met with the Company on Friday August the 6th.

Q. What were the results of the settlement meeting?

A. Some parties including RUCO have settled on a revenue requirement of $81,497,921, see attachment A.

Q. Please highlight some of the major areas that the Company, RUCO and other parties in this proceeding were able to reach agreement.

A. While I will not address every issue reached in the settlement agreement just those dealing with revenue requirement, I will go over some of the major points in the settlement agreement that benefit ratepayers that relate to settled revenue requirement. The Company, RUCO and other parties to the settlement have agreed to:

- A permanent write down of the Net Book Value of the TEP headquarters by $5 million which results in a $5 million dollar reduction to Original Cost Rate Base. This will resolve the TEP headquarters issue that was an issue in the last rate case, and in this rate case, and going forward.

- The inclusion of post-test year plant that was in service as of June 30, 2016 in the amount of $49.6 million, and post-test year renewable generation plant in the amount of $4.8 million. Which is a reduction of $18.1 million[1] from what the Company requested in Rebuttal testimony.

[1] See Company Rebuttal Schedule B-2, Page 2 of 5.

- As laid out in Attachment A, the following changes to depreciation and amortization rates were negotiated by the parties that were previously in dispute:
  - (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.

- Additional provisions include the following:
  - (i) A six year historical average of outage expenses.
  - (ii) Exclusion of 2017 payroll expense of 2 percent related to non-classified employees.
  - (iii) A 50/50 sharing of short-term incentive compensation.
  - (iv) Rate case expense of $1 million normalized over four years, and
  - (v) Removal of $1.1 million associated with litigation costs related to Alterna.

Q. Any other comments on the settled revenue requirement of $81,497,921?

A. Yes. $15,243,913 of revenue requirement increase is related to the non-fuel operating costs associated with the Company's 50.5 percent share of

Springerville Generating Station ("SGS") Unit 1. The Company in its direct testimony requested that this amount be passed through the Purchased Power and Fuel Adjustment Clause ("PPFAC"). Since that time the Company now owns 100 percent of SGS Unit 1, the Company has asked that the $15,243,913 be included in operating expenses, and removed from the PPFAC. Stated another way the ratepayers would have to pay for this either through the PPFAC or through base rates, and thus any perception that RUCO has agreed to an additional increase of $15,243,913 is untrue.

III. OTHER ISSUES

Q. Are there any remaining issues that you testified to in direct testimony that were not settled?

A. Yes. The expansion of the adjustor mechanisms and the Company's weather normalization.

Expansion of Current Adjustor Mechanisms

Q. You discussed the Company's expansion of their current Adjustor Mechanisms in direct testimony?

A. Yes.

Q. Do you have anything new to add?

A. Yes, just briefly. The recommended order and opinion issued by the administrative law judge in Docket No. E-04204A-15-0142, addressed the Lost Fixed Cost Recovery ("LFCR") Mechanism. "UNSE has not met its burden to show that its proposed changes to the LFCR mechanism are in the public interest. The LFCR mechanism is not intended to operate as a full De-coupler mechanism, but rather to collect the lost fixed cost revenues associated with Commission-mandated programs such as Energy Efficiency and DG." [2]

Similarly, regarding the Purchased Power and Fuel Adjustment Clause ("PPFAC"). "The Company has not presented a compelling reason for changing the current method of allocating fuel costs among the various rate classes in the PPFAC. Therefore, for the reasons set forth by Staff and RUCO, we decline to adopt UNSEE's proposed PPFAC modifications".[3]

Weather Normalization

Q. In your direct testimony RUCO recommended that the Company file an annual report that showed the impact of weather normalization on the Company's revenue?

A. Yes.

Q. What was the Company's response?

A. The Company in its rebuttal testimony stated that it could file the annual report, but it would be time consuming, and would seek recovery from the ratepayers of any costs incurred to provide this information.

Q. What is RUCO's response?

A. RUCO will withdraw the request at this time, but this does not preclude RUCO from revisiting this issue in the next rate case.

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[2] See page 123, line 2.
[3] See page 118, line 18.

Q. Does this conclude your rebuttal testimony?

A. Yes.

ATTACHMENT A

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)	(57,652,694)	(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)	
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)	(42,256,127)	(53,379,783)	(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	2,066,327,115	2,045,203,460		
Proposed Rate of Return	7.34%	7.16%	7.04%		
Required Operating Income OCRB	$154,416,180	$147,984,232	$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	165,888,315	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		
<u>Operating Income Adjustments</u>					
<u>Operating Revenue Adjustments</u>					
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 five million dollar write-down to the Headquarters Building per ACC Jurisdiction.
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	5,644,715	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	702,980	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	-	4,568,108	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)	(17,595,211)	(1,564,859)	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	95,464,852	93,719,409	90,043,570	(5,421,282)	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		

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. W-01933A-15-0322

SURREBUTTAL TESTIMONY AND SETTLEMENT TESTIMONY OF FRANK RADIGAN

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

AUGUST 25, 2016

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INTRODUCTION

Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is Frank W. Radigan. I am a principal in the Hudson River Energy Group, a consulting firm providing services in electric, gas and water utility industry matters, and specializing in the fields of rates, planning and utility economics. My office address is 235 Lark Street, Albany, New York 12210.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes, on June 3, 2016 I submitted testimony on behalf of the Residential Utility Consumer Office ("RUCO") with respect to certain revenue requirement issues in this case. On June 24, 2016 I submitted testimony which addressed other aspects of Tucson Electric Power Company's presentation ("TEP" or "the Company") with respect to revenue allocation and rate design. At that time, RUCO witness Lon Huber also submitted testimony with respect to rate design issues.

SCOPE OF TESTIMONY

Q. WHAT IS THE SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been asked to review the Settlement Agreement submitted on August 15, 2016 with respect to the revenue requirement aspects of this case and comment on the rebuttal testimony of parties as it relates to 1) revenue allocation of the rate increase amongst service classes and 2) the proposed consolidation/elimination of many of the lifeline rate rates.

SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Under the terms of the Settlement Agreement TEP shall receive a non-fuel base rate increase of $81.5 million over adjusted test year non-fuel retail revenues. This compares to TEP's initial request for a non-fuel base rate increase of $109.5 million. Of the allowed non-fuel base rate increase, $15.2 million is contingent upon TEP purchasing a 50.5% share of Unit I of Springerville Generating Station ("SGS Unit 1). In the original filing TEP proposed to recover the $15.2 million of costs related to SGS Unit 1 in the PPFAC but now proposes to recover that money in base rates. Thus, the costs related to SGS Unit 1 are revenue neutral and the non-fuel base rate increase in the settlement as compared to the original filing is $66.3 million or $43.2 million less than the Company originally asked for. Stated another way TEP has settled for approximately 60% of the base rate increase it originally sought. I note that many of the adjustments that RUCO witnesses made in original testimony were addressed in the settlement, which I will address in more detail below. Overall while RUCO did not get all it was seeking in the case, and neither did the Company or Staff, I believe the Settlement Agreement is a fair outcome to the rate case.

There is one issue that does not impact the base rate increase addressed in the settlement but does impact the overall rates that customers pay as it would flow through the PPFAC. That issue which was not addressed in the Settlement Agreement is the rate treatment of non-jurisdictional sales above the amount imputed into base rates. Long term wholesale sales, contracts over a year in length, are sold at rates approved by the Federal Energy Regulatory Commission and are known as non-jurisdictional sales. The assets to make these sales are the Company's generating units. For ratemaking purposes an estimate of the amount of non-jurisdictional sales is made and excluded from the income statement. In this case the Settlement imputed a certain number of non-jurisdictional sales but we know that some contracts will be in place after the rates in this case are set and the Company has a long history of entering into these contracts when opportunities arise. If no rate treatment is specified for the treatment of the profits from these transactions the Company will be allowed to retain 100% of profits from generating units whose costs are supported by retail ratepayers. This would be inequitable and I propose that 80% of the profits from these sales be passed back to retail ratepayers and 20% be retained by the Company as an incentive to keep making off system sales when the opportunity arises.

The last issue I address is the importance to note that the Settlement Agreement did not address the rate design aspects of the case and some of those are still in contention. In my original rate design testimony I noted that while TEP proposed revenue allocation did follow the general results of the embedded cost of service study, I believe the relative rates of return of the service classes could be better improved if one more closely followed the results of the cost of service study. I have reviewed the direct testimony of Staff Witness Solganick on this subject as well as the Rebuttal Testimony of Craig A. Jones. I would note that Staff witness Solganick's recommended revenue allocation closely resembled mine. I also note that while Mr. Jones recommended allocation in rebuttal testimony better aligned the recommended revenue allocation with the results of the cost of service study, I believe both mine and Staff's followed the results closer and resulted in rates that were closer to the cost to service as indicated by the cost of service study. At this point in the proceeding RUCO would support Staff's recommend revenue allocation as adjusted for the Settlement Agreement recommended rate increase.

For Lifeline rates, given the very large rate increase that the Company is proposing after reading Mr. Jones rebuttal testimony on this issue, I continue to not support the Company's proposal to reduce the current 27 rate offerings down to 5. As I noted in my original rate design testimony while I do not object to the Company's proposal for new customers where they will receive a fixed discount, the proposal for the existing customers is unacceptable from a customer impact point of view. I propose that the

Company reconsider its proposal and 1) develop a new one where existing frozen classes remain as is, and 2) for non-frozen classes, redevelop a rate proposal that does not result in undue customer rate impacts.

REVENUE REQUIREMENT

Q. PLEASE COMMENT ON THE REASONABLENESS OF THE NON-FUEL BASE RATE INCREASE CONTAINED IN THE SETTLEMENT AGREEMENT.

A. Under the terms of the Settlement Agreement TEP shall receive a non-fuel base rate increase of $81.5 million over adjusted test year non-fuel retail revenues. This compares to TEP's initial request for a non-fuel base rate increase of $109.5 million. Of the allowed non-fuel base rate increase, $15.2 million is contingent upon TEP purchasing a 50.5% share of Unit I of Springerville Generating Station ("SGS Unit 1). In the original filing TEP proposed to recover the $15.2 million of costs related to SGS Unit 1 in the PPFAC but not proposes to recover that money in base rates. Thus, the costs related to SGS Unit 1 are revenue neutral and the non-fuel base rate increase in the settlement as compared to the original filing is $66.3 million or $43.2 million less than the Company originally asked for. Stated another way TEP has settled for approximately 60% of the base rate increase it originally sought.

In my revenue requirement testimony in the case I testified on the proper level of the jurisdictional sales allocator which reflects the impact of wholesale power sales that TEP makes with its generation assets, the proper level of post test year plant, depreciation expense relating to generating plants, weather normalization of residential retail sales and the appropriate rate treatment of the Company's headquarters building. Post test year plant, depreciation expense relating to generating plants, the jurisdictional sales allocator and the rate treatment of the headquarters building were all directly addressed in the terms of the Settlement Agreement. These issues together with other issues raised by the other RUCO witnesses, Mr. Mease and Milchik, most notably rate of return and employee compensation/benefits are all reflected in the terms of the Settlement Agreement and played a significant part in reducing the rate request. Overall, while RUCO did not get all it was seeking in the case I believe the Settlement Agreement is a fair outcome to the rate case.

Q. COULD YOU PLEASE COMMENT ON THE RATE TREATMENT OF NON-JURISDICTIONAL SALES ABOVE THE AMOUNT IMPUTED IN RATES?

A. Yes, the settlement agreement reflects TEP's rebuttal positon on the imputation level of non-jurisdictional sales in rates. Long term wholesale sales, contracts over a year in length, are sold at rates approved by the Federal Energy Regulatory Commission. In the Company's presentation it adjusts the income statement and rate base calculations so that the plant associated with these transactions are not recovered within jurisdictional base rates (Dukes direct at 51). In its original presentation TEP developed their pro-forma adjustment the Company removed 200 MW out of the 296 MW of FERC jurisdictional contracts that were in place in the test year. TEP excluded two expiring long-term wholesale contracts with Salt River Project ("SRP") and Shell Energy (100 MW each) because the SRP contract expired on May 31, 2016 it excluded the Shell Energy contract because it will only be in effect for one year after rates are set in this rate case proceeding (Sheehan rebuttal at page 8). The exclusion of what contracts to include and what contract to exclude became an issue in the rate case and in rebuttal TEP proposed a pro forma adjustments that include a new long-term wholesale contract that was entered into with Navopache Electric Cooperative ("NEC") in September 2015 (Ibid).

While this provides a level of wholesale sales imputed for ratemaking purposes in the Settlement Agreement the issue does not end there. For example we know the Shell contract will be in place after rates are set and if nothing else is done the utility will be allowed to keep all profits from this contract. In addition, per the Company's 2016 IRP we know the contract with the TRICO Electric Cooperative will increase in 2018 from 50 MW to

85 MW and sales will double from 40 GWH to 83 GWH.[1] If this is unaddressed it would just benefit the utility even though we are positive that it is going to happen. Both of these contracts were entered into after the Company purchased Gila River 3 whose costs are now reflected in rates. It is inequitable for the Company to profit off the sales of generator output that is supported by retail customers. The Company should still have an incentive to make these sales, however, or else they just wouldn't bother and both the utility and ratepayers would be worse off. Thus, I propose that 80% of the profits from these sales be passed back to retail ratepayers and 20% be retained by the Company as an incentive to keep making off system sales when the opportunity arises.

REVENUE ALLOCATION

Q. COULD YOU PLEASE DISCUSS THE ISSUE OF REVENUE ALLOCATION?

A. As I noted in my original rate design testimony revenue allocation is a two part exercise where the first step is to correct for any imbalances that exist between service classes in providing the utility an adequate rate of return and the second is to allocate the rate increase among service classes. In the first step, the results of the cost of service study are reviewed to determine how each service classification is doing with respect to providing

[1] TEP 2016 IRP, page 30

the utility with the earned rate of return. If a service class is providing less than the average, in an ideal world, it should be given a greater than average increase to bring its earned rate of return up to the average. For example, if the utility is earning a 10% overall average rate of return and one particular service class is earning a 7% rate of return while another is earning a 13% rate of return, then the rate designed would give a higher than average increase to the first service class, in the example, and a lower than average increase to the second service class, in the example.

Q. COULD YOU PLEASE SUMMARIZE WHERE PARTIES ARE AT THIS STAGE IN THE PROCEEDING?

A. Yes. In my original rate design testimony I proposed an alternative to the Company's recommended allocation and I note that Staff did as well. The Company adjusted it position in the rebuttal testimony of Craig Jones. While mine and the Company's original position was based on TEP's original proposed revenue requirement, Staff's recommended allocation was based on its recommended revenue requirement and the Company's rebuttal positon was based on its updated revenue requirement. In order to get each parties positon on revenue allocation in the proper perspective of one another I developed the table below which shows how much each party is allocating to a service class relative to the overall average. Put another way, if a party is recommending one service class get a 15% increase while the utility overall is getting a 10% increase then that class would be getting 1.5 times the average. If the overall average was 8% and the service class was getting a 12% increase it would be still getting 1.5 times the average increase. Again, any time a service class gets more than an average increase it improves the relative rate of return of the class.

TEP
Revenue Allocation - % Increase Relative to Overall Increase

	Company Original	Staff	RUCO	Company Rebuttal	UROR as Filed
Res	0.88	1.90	1.60	1.39	-0.29
GS	0.24	0.16	0.39	0.18	3.50
LGS	3.07	0.21	1.03	2.45	0.83
LPS	0.11	n/a	0.30	-5.31	2.42
Lighting	2.09	4.25	1.66	2.65	-2.86
Total	1.00	1.00	1.00	1.00	1.00

I have also included a column which shows the relative contribution of each service class relative to the Uniform Rate of Return. This is helpful as a metric to compare how each service class is providing a rate of return relative to the overall rate of return of the utility. For example if the utility is earning an overall 8% rate of return and service class ABC is earning an 6% rate of return it is 0.75 relative to the total. If service class XYZ was earning a 13% rate of return it would earning 1.625 times relative to the total. This way one can easily see that a service class with a relative rate of return lower than 1.0 should get an above average increase and one with a relative rate of return greater than 1.0 should get a less than average increase.

Based on this table I conclude that both Staff and my recommended revenue allocation are most in line with the results of the cost of service study and either could be used to set rates. Staff's method was based on a series of runs of the cost of service model and moving the Residential and Lighting Classes closer to parity (Solganick Direct at page 23). They then chose one that they thought best balanced rate impacts and the results of the cost of service study. My method was more based on first rate impacts and second on the results of the cost of service study. That cannot be said for the Company's original or rebuttal position. In both cases it punishes the Large General Service Class by giving much higher increases while favoring the Large Power Service Class. Staff's method is more formalistic and can be more easily used in whatever revenue requirement results from the case as it is based on a precise measure of how much each class should move. As such, I recommend that Staff's method be used to design the final revenue allocation in the case.

RATE DESIGN

Q. WHAT IS YOUR RECOMMENDED RATE DESIGN FOR THE LIFELINE RATES?

A. In its original presentation Company witness Jones proposed major changes to its low income rates which are referred to as Lifeline rates. The Company proposes to change the current rates that give either a fixed discount or discounts from the otherwise applicable rates to a single uniform discount off of each of the residential rates (Jones Direct at 57). The modifications would reduce the 27 existing tariffs down to five different open rate options, one for each of the five existing residential rates, and apply a flat $15.00 per month discount, limited to a reduction of the bill down to zero dollars (Ibid). The Company is also proposed changes to its frozen Lifeline rate options that will reduce them from 22 to five different options (Jones Direct at 58).

Q. COULD YOU PLEASE COMMENT ON THE COMPANY'S PROPOSAL?

A. In my rate design testimony I noted that the Company's proposal resulted in very large rate increases to the customers being served under the lifeline rate options being proposed by the Company (Radigan Direct on Rate Design at 10). Moreover, I noted that the Company's proposal is not supported by the facts as presented. Many of these existing rates receive either a fixed discount in dollars or a discount as a percentage. As these are existing in the current billing program there is little administration to them. In addition, many of these rates are frozen, 22 of them, and don't even apply to new customers. The fact that the Company states that 11 of the 27 rate schedules have less than 20 customers on them so the question must be asked as to why even bother going to so much effort for so few (Ibid). In rebuttal testimony Mr. Jones states that I make light of the burden this puts on the Company (Jones Rebuttal at age 49). He notes that it is burdensome because no matter how few customers the class is tracked for reporting purposes and be included in every report (Ibid). He states this takes a great deal of time and effort (Ibid).

Mr. Jones also responded to my comment that I could find no evidence that it proposed the envisioned cost reductions due to the elimination of these service classes by stating that the Company is trying to identify an area that can be streamlined in a way that will <u>eventually</u> allow for more productive use of employees time and our customer's dollars (Jones rebuttal at 50, emphasis added).

Q. PLEASE RESPOND TO MR. JONES.

A. I do not make light of the situation but I must note that these are exiting customers who are already in the billing system, already in all reports and most of the rate frozen so that new customers are not allowed in which would add to the Company's daily work load. I do not discredit that the Company has to put effort into maintaining these rates but I balanced that against the large increases being proposed (Per Jones Rebuttal CAJ R-3, Schedule H 2-2 some lifeline rate options receiving 50% increases per subclass) and simply stated that the Company's proposal not be imposed on existing customers due to the rate impacts. I also balanced the fact that the Company's proposed cost savings are unidentified and may only occur far out into the future. In sum, I do not make light of the Company's presentation but could find no evidence that it has merit when measured against the certain large rate impacts being proposed.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY AND TESTIMONY IN SUPPORT OF THE SETTLEMENT?

A. Yes, it does.

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. W-01933A-15-0322

SURREBUTTAL TESTIMONY AND

SETTLEMENT TESTIMONY

OF

LON HUBER

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

AUGUST 25, 2016

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INTRODUCTION

Q. How is your Surrebuttal Testimony organized?

A. I intend to first provide a summary of RUCO's position, then address the rebuttal testimonies of witnesses Overcast and Jones together in the following format:

1. RUCO's recommendations
2. Allocation of Distribution System Costs
3. Rate Mechanism for Recovery of Fixed Costs
4. Recent Fixed Charge Proposals
5. Concerns Regarding Fixed Charges
6. Earnings Risk
7. Tiered Rates

Q. Do you have any corrections to your direct testimony?

A. Yes, on page 32 line 14, strike RUCO and insert TEP.

Q. Do you have any modifications or additions to your rate design proposals presented in your Direct Testimony?

A. Yes, based on the recent UNS Electric ACC decision, I recommend several modifications to the positions put forward in my Direct Testimony. These include:

1. Recommend setting the fixed charge on Time-of Use ("TOU") based rates to $10 and $13 for non-TOU or demand rate plans

2. Recommend adopting a two window winter peak for the RUCO default TOU rate
3. Recommend adopting RUCO's RPS Credit option (also labeled the RES Credit option in Direct Testimony) in the interim before Phase II. Customers could have the option to apply the credit rate on all their production or just exports.
4. Recommend the approval of TORS program
5. Recommend a $6 meter fee in the interim for those on the net metering rider

One could argue that the theme of the UNS Electric rate case was the modernization of rates. In fact, Judge Rodda in the ROO for UNS Electric rate case may have put it best when she said "the time is ripe for a more modern rate design."[1] In the UNS Electric decision, a strategy was implemented to take the beginning steps of modernizing rates by:

- Incentivizing customers on two-part traditional rates to switch to a Time-of Use ("TOU") based rate. This is because TOU based rates align closer to system costs and send better price signals to customers than a two-part traditional rate. The strategy implemented sets a date for transition, about six months out, when the fixed charge on all TOU based rates will be reduced from $15 to $12. The fixed charge on the two-part traditional rate would remain at $15. This $3 differential will provide the incentive for customers to select a TOU based rate.

[1] UNS Electric Recommended Opinion & Order Page 66 Line 9

- The two-part TOU rate offered by UNS Electric, now becomes the default rate for all new residential customers.
- Addressing the Company's three-part mandatory demand charge for DG customers and changes to net-metering, were moved into a Phase II which is to commence once the open Value of Solar Docket has concluded.
- RUCO's RPS Credit option was adopted as another option for DG customers that provides certainty for both DG customers and non-DG customers alike and is not reliant on rate design for DG customers or the Value of Solar docket.
- A meter charge was implemented for DG customers to account for the increased costs of providing service to a DG customer.

1. <u>RUCO's Recommendations</u>

a. Rate Design for All Residential Customers

Q. What is RUCO's recommendation regarding fixed charges for residential customers?

A. In order to modernize rate design and incentivize the adoption of more TOU rates, RUCO recommends a strategy much like that adopted in the UNS Electric rate case. The fixed charge for all rates should be increased to $13 after the Commission order. An educational campaign, lasting six months from the date of final order, should then be undertaken, by the Company, to educate customers about TOU rates and the tools provided to allow customers to control their usage and be successful on these types of rates. At the end of the six months, the fixed charge on TOU based rates should be reduced to $10. This provides the same incentive as the UNS Electric rate case, enticing customers to transition to TOU rates. Although there is no evidentiary basis for a fixed charge higher than $10, raising the fixed charge to $13 provides the needed amount of fixed charge differential to create an incentive for customers to select TOU based rates. The proposed timing also minimizes the argument that increasing the fixed charge only on two-part traditional rates is punitive.

Q. What is RUCO's recommendation for a default rate for residential customers?

A. RUCO continues to recommend that the Company's default rate for new residential customers, and large customers, should be RUCO's two-part TOU rate. This recommendation continues the theme of modernizing rates, while maintaining customer choice.

Q. Did the UNS Electric decision provide a guide for the TOU periods?

A. Yes, a four hour peak period with two time windows for the dual winter peak. RUCO's proposed default TOU had this exact same four hour window. To conform with Commission direction regarding the winter peaks and the fixed charge differential, I have slightly modified RUCO's proposed default TOU.

Full Requirements TOU Rate

Basic Monthly 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 Hour Start	3:00 PM	6:00 AM & PM
Peak Hour End	7:00 PM	9:00 AM & PM

Three-Part Optional Rate

Basic Monthly 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	$ 0.0385	$ 0.0295

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 Hour Start	3:00 PM	6:00 AM & PM
Peak Hour End	7:00 PM	9:00 AM & PM

b. RPS Credit Option

Q. In light of the procedural order that created a Phase II for this rate case, should RUCO's recommendations of the RPS Credit option and meter charge be pushed to Phase II?

A. No, the idea of the Phase II proceeding, in this case, came from the UNS Electric rate case and RUCO would argue that it is designed to mirror it. The motion filed by the Company in this case, requesting a Phase II proceeding, is limited in scope to "changes to net metering and mandatory three-part rates for new DG customers." The language in the procedural order limits the scope of Phase II to issues "related to changes to net metering and rate design for new DG customers." Neither the RPS Credit option nor the meter charge for DG customers falls within either of these scopes. If one were to argue that they did, they would also, by implication, have to argue that revenue allocation, revenue requirement, and fixed charges are also related. This type of reasoning seems to go far beyond the spirit and intent of the Phase II proceeding, which is to wait until the Value of Solar docket is complete to make decisions on issues in this case, that are directly impacted by that docket.

Additionally, in the UNS Electric rate case, Commissioners Stump and Tobin each proposed amendment that were subsequently adopted unanimously by the commission, specifically relating to RUCO's proposed RPS Credit option and the metering charge for DG customers. By the Commissioners not pushing these issues to Phase II, they demonstrated that these issues either 1) needed to be addressed with some urgency or, 2) as RUCO suggests, there was no need to wait because they were separate from the issues directly related to the Value of Solar docket. Either way, it is clear that there is no need to push these issues into the

Phase II proceeding. Now is the time to address them. Keeping these options on the table for Commissioner consideration, as intended, is the prudent thing to do.

Q. Does RUCO still support the RPS Credit Option?

A. Absolutely, with one modification. To accommodate concerns heard from solar roof top representatives, RUCO now allows a choice to prospective solar customers about whether or not they want the credit rate applied to all of their production or just exports.

Q. Do export only customers fully count towards the capacity in a given tranche?

A. Yes, the full system capacity would apply.

Q. For the "Capacity per Tranche" figures in your Direct Testimony, please provide the basis for the level of capacity in each tranche.

A. The basis for each capacity tranche in the RPS Credit Option was formulated to create an average blended rate across all tranches of around 7.7 cents/kWh. This conforms with RUCO's long-term breakeven analysis. The capacity targets are also close to yearly REST compliance targets.

Q. For the "Price per Tranche" figures in your Direct Testimony, please provide the basis for the rate level in each tranche.

A. RUCO attempted to set the decline rate roughly equal to historical system cost declines. RUCO chose a yearly 7% decline rate. Reported system prices of residential and commercial PV systems declined 6%–7% per year, on average, from 1998– 2013, and by 12%–15% from 2012–2013 (depending on system size).[2]

Q. Please indicate whether and how the proposed rate for the final tranche would be updated over time.

A. The final rate would be the Market Cost Comparable Conventional Generation ("MCCCG") rate plus any adder the Commission deems reasonable in a post-RPS compliance environment to recognize the local renewable energy attributes. The MCCCG rate is updated every year.

Q. Can a customer's fixed charge be reduced through the RPS credit Option?

A. Assuming a large enough system, yes.

Q. Are there other details to call out?

A. Perhaps. RUCO does not intend to stray from current DG related rules when approaching the RPS Credit Option. For example, a bill could not go negative and

[2] Photovoltaic System Pricing Trends, 2014 Edition, US DOE SunShot: http://www.nrel.gov/docs/fy14osti/62558.pdf

any excess would be paid out at wholesale rates during the same time period that currently exists for NEM.

Q. What about concerns of customer confusion with the step downs?

A. Just like UFI's, I fully expect the Company will provide adequate notice when a capacity tranche starts to run out of capacity. As an example, like years before, TEP would notify the installer listserv and post a message on the website.

Q. Can capacity levels and credit rates be adjusted on a going forward basis in the months and years ahead?

A. Absolutely. The structure is very flexible to accommodate new policy directions, technology, locational data, etc. Unlike net metering, the RPS Credit Option can accommodate the following:

1. State policy goals that guide the capacity targets
2. Locational value, technology (west facing, advanced inverter) and reliability adders can be integrated into credit rates
3. Regular check-ins can occur at Commission discretion to respond to changing market conditions and technological developments
4. More peak demand based rates because the value proposition does not depend upon the underlying rate design, so one can couple EE and demand reducing technologies with solar without tradeoffs.

Finally, if the Commission so wishes, the RPS Credit Option can easily be adapted to incorporate the outcome of the Value of Solar docket.

Q. Did RUCO review the TORS program?

A. Yes, RUCO reviewed the TEP Owned Residential Solar (TORS) program with a particular focus on the cost parity issue. I found that TEP owned rooftop solar were 44% less expensive than a NEM based PV system on current rates. While that figure drops to approximately 25% less expensive, if a societal time value of money rate is applied, I did not factor in lost adjuster revenue or local tax revenue losses from NEM based systems.

Q. Does this conform with earlier opinions on the program?

A. Yes, and then some. The benefits to ratepayers is higher than anticipated and I am not even factoring in other possible benefits of the TEP program that are not provided by NEM based systems. What the analysis points to is that rooftop solar can be obtained for a much lower price to the benefit of all ratepayers.

Q. Do existing TORS systems align with the cost parity principle?

A. Yes.

Q. Does RUCO continue to support the expansion of the TORS program?

A. Very much so.

c. Meter Fee

Q. Does RUCO recommend a $6 meter fee for net metering customers?

A. Yes.

Q. How did RUCO arrive at this figure?

A. RUCO utilized TEP filed REST implementation plan budgets to determine that the Company charges for the direct hardware costs of solar specific metering through the REST surcharge. RUCO then examined the TEP marginal cost study CAJ-1, Schedule 1, to estimate the administrative costs and the monthly hardware related costs per customer. To simplify the calculation, RUCO made the assumption that there is not a substantial cost difference between a standard residential AMR meter and a PV production meter. This relates to both hard and soft costs. To formulate the monthly amount from the marginal cost study, RUCO added lines 5, 13, half of line 14, 18, 19, and 20 to arrive at a figure around $6 per month. It is important to note that this figure errs on the conservative side because it does not take into account the incremental additional cost of an "upgraded" bi directional meter a solar customer also needs.

2. Allocation of Distribution System Costs

Q. Are there cases where public utility commissions have adopted the use of the basic customer method over the minimum system method to allocate distribution system costs?

A. Yes, there are many. I will provide just a few examples. In Utah, the Public Service Commission adopted a classification system mostly based on demand and rejected use of the minimum distribution system method[3]. In Washington, the Commission also rejected the minimum system method stating that "the minimum system method is likely to lead to the double allocation of costs to residential customers and over-allocation of costs to low-use customers.[4]" In Maryland, in a case with Baltimore Gas and Electric, the Commission approved the NCP method and rejected the minimum size method[5]. According to witness Baatz, "the basic service method (also known as the basic customer method) is a common method used in over 30 states."[6]

Q. Please summarize the Company's argument against use of the basic customer method to allocate customer costs.

A. The crux of the Company's argument against the basic customer method is reflected in the following statement by witness Overcast: "advocates of the basic customer method fail to recognize that class NCP is more appropriately used in

[3] Utah PSC Order, Docket No. 81-035-13.
[4] WUTC v. Puget Sound Power and Light Company, Cause U-89-2688-T, Third Supp. Order, P. 71, 1990.
[5] Maryland PSC Case No. 8070.
[6] Baatz, p 9, line 7

circumstances where there is far more diversity in load (e.g. at the substation). Class NCP alone is inappropriate for local facilities that are closer in proximity to customers they serve."[7]

Q. What is the problem with this reasoning?

A. What witness Overcast fails to mention is that there is increased diversity in load for *any* common facility that is shared among multiple users. This is true not just of transmission transformers, or substations, or feeder lines, it is true even of local branch lines feeding individual customers. Moreover, he fails to define exactly how close to the customer a facility needs to be before it becomes a "customer facility." No clear rationale or boundary is presented for when and where certain facilities that are common to many users should be considered customer-related costs versus demand- or energy-related costs.

Q. What does RUCO believe the appropriate boundary should be?

A. RUCO believes that any common facility that has the potential to be shared by multiple users should not be classified as a customer-related cost, and therefore should not be recovered through a fixed customer charge. Failure to provide this clear boundary would create a slippery slope whereby any common facility – all the way up to the power plant – could be labeled as a "customer cost." Such an

[7] Overcast, p 13, line 20

outcome is neither fair nor logical, and would not promote efficient consumer behavior.

Q. What does RUCO think the Company intends to propose in the long term?

A. The CCOSS completed by the Company indicates each customer incurs a fixed cost of $93.61 per month[8]. It can be inferred that the Company aspires to a $93.61 per month customer charge in the long term. The discussion of increased fixed charge beyond the current $10 per month and even the proposed $20 per month in this docket will likely just continue unless the Commission establishes a clear precedent for which costs are appropriate to include in a fixed customer charge.

Q. Why is a discussion of a fixed charge between the current $10 per month and the CCOSS $93.61 per month concerning?

A. Not only is RUCO is deeply concerned about the prospect of a $93.61 per month fixed charge, RUCO is also concerned that a ruling that does not address the boundaries of residential customer charges will make this topic one of the most contentious issues in all future rate cases. Utility fixed costs are not a new occurrence; utilities have always had high fixed costs. Moreover, the ask for higher charges are not due to the availability of any new technologies. Therefore, without a fence line, the Company is likely to continue to propose increasingly higher fixed charge between the currently approved customer charge and the CCOSS $93.61.

[8] Direct Testimony of Craig Jones p. 44, line 2

Q. Witness Overcast claims that the basic customer method is at odds with the NARUC Electric Utility Cost Allocation Manual. Is this true?

A. This does not appear true from the evidence presented. Overcast points to a passage from the NARUC Manual which states that "the utility must classify distribution plant data separately into demand- and customer- related costs."[9] However, the basic customer method also does this. The only difference is that the basic customer method classifies customer-related distribution costs more precisely than what the Company has proposed. That is, the distribution plant designated as customer-related is limited to the service drop and customer meter.

Q. Does the NARUC Manual provide any caveats on the use of the minimum system method?

A. Yes. The manual states: "Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost."[10]

[9] Overcast, p 14, line 14.
[10] NARUC, Electric Utility Cost Allocation Manual p 95.

Q. What limitations could there be in relying on any approach outlined in the NARUC manual?

A. Generally speaking, traditional cost classification methodologies, including those outlined in the NARUC Manual, start from the premise that there are only three types of cost drivers: energy, demand, and customer. In reality, there could be many, many more factors that are left out of this initial list. For example, in a rural community the number of poles, and length of conductor required may be more linked to the distance to reach each remote property than it is to the overall number of customers. However, the manual does not include a "Distance from Substation" classification through which these incremental costs could be assigned. Thus, the default tendency is to assign costs driven by these other factors (other than energy, demand, or customer) to the customer category, even if they are not customer-driven.

Q. What does RUCO suggest to overcome these limitations?

A. Short of a radically different method for classifying costs that includes a variety of other factors, RUCO believes that a fair way to allocate costs is to apply a "benefits received" principle.

Q. What other literature does Overcast cite in support of the minimum system method?

A. Most of the writings that Overcast cites are decades old, including articles from 1891 (Clark), 1896 (Greene), 1900 (Doherty), 1919 (Eisenmenger), 1956 (Caywood), 1963 (Bary), and 1991 (NARUC).

Q. How does RUCO think these texts should be considered?

A. We should approach these with caution. By Overcast's own standard, reports as recent as 2000 are "dated" and do not "have the advantage of the latest empirical research[11]." Relying predominantly on older writings suggest that industry practices and thinking have not changed over the last 25 to 125 years. It also presents a false notion that there is some scientifically perfected approach to cost allocation that has evolved over the years. The reality is that there is always some subjectivity involved and there are many just and reasonable rates that commissions have adopted over the years that do not conform to the minimum system approach.

[11] Overcast, p 39, line 20.

Q. Witness Overcast claims to present empirical evidence proving a causal relationship between distribution system costs and number of customers. Does RUCO believe the empirical data presented supports this conclusion?

A. No. Overcast presents two pieces of evidence to support this claim, but neither succeeds in proving causality.

Q. Please explain.

A. The first piece of evidence presented is a regression analysis in which customers are set as the independent variable and distribution plant costs are set as the dependent variable[12]. However, Overcast's approach omits many other potential explanatory variables, besides number of customers, that could also be used to demonstrate causality. In fact, Omitted-Variable Bias is recognized by statisticians as one of the major pitfalls that must be avoided in any statistical analysis that is seeking to demonstrate causality[13]. There are many potential explanatory variables that Overcast omitted in his analysis, including total kWh sales, total kW demand, size of the typical or average new customer (kW), size of the customer lot (acreage), geographic location, distance from substation, local jurisdiction, time, value of assets that have reached their useful life (among a long list of others). Without a comprehensive analysis of these and other variables it is not possible to conclude that distribution costs have a causal link specifically to number of customers.

[12] Overcast, p 36, line 18.
[13] See for example: http://statisticalhorizons.com/prediction-vs-causation-in-regression-analysis

Q. Does the Company agree that costs classified as "customer costs" could be driven by factors other than the number of customers?

A. Yes. In his direct testimony, witness Jones stated: "a utility incurs costs based on: (1) the number, *size, geographic location and type* of customers; (2) a combination of several measures of customer demand; or (3) a measure of the energy used by customers"[14] (emphasis added).

Q. What other evidence does witness Overcast provide?

A. The second piece of evidence includes a table examining the number of distribution transformers used by the residential class compared to the total system[15]. There are two problems with this analysis. First, the total number of transformers used by the residential customer class may not be reflective of the total cost of those transformers. Second some transformers could be used by multiple customer classes. Without insight into both of these factors, it is not possible to conclude which allocation method better reflects distribution cost causation.

[14] Jones, direct testimony, p 18.
[15] Overcast, p 37, line 4.

3. <u>Rate mechanisms for recovery of fixed costs</u>

a. Using fixed charges to recover fixed costs

Q. Does witness Overcast's rebuttal testimony on page 29 accurately characterize RUCO's position on recovery of fixed costs via fixed charges?

A. No. Witness Overcast misinterprets RUCO's position. RUCO has never claimed that fixed charges should never be used, or that they are never justified. But rather, RUCO is merely observing that there is no scientific based reason that fixed charges *must* be used to recover fixed costs. Moreover, there is no scientific rule regarding the amount of fixed costs that *should* be recovered in fixed customer charges. Instead, there is a great degree of subjectivity in how rates can be designed to recover fixed costs and the many considerations that must be balanced.

Q. Are there any examples in Arizona where a customer-related fixed cost was not recovered through a corresponding fixed charge for subjective policy reasons?

A. Yes. One example of this is the current policy the Commission has approved for line extensions. This is a clear case in which customer is imposing a cost on the distribution system, yet these costs are not recovered by that customer through corresponding fixed charge. In fact, the link between the specific customer and specific cost imposed is much more clear cut in that instance than what TEP has proposed. It also demonstrates that the principle of cost causation, while important, is not strictly applied or is not the sole determining factor in all cases.

Q. Given that the principle of cost causation is not the sole determining factor, what are some other considerations beyond cost causation that must be balanced in rate design?

A. There are many factors that must be balanced including economic efficiency, avoidance of undue discrimination, rate stability, and promoting efficient use of energy over the long term.

Q. Does Dr. Overcast appropriately balance all of these considerations?

A. No. Dr. Overcast seems to suggest that the overriding factor upon which rates should be determined is a narrow definition of what constitutes "economically efficient rates." In reality, academic theories about which rates are most efficient is simply one factor that must be balanced against other factors for determining just and reasonable rates, and should not overshadow other equally important factors.

Q. Witness Overcast states that "rate practitioners have recognized the need to recover fixed customer costs in fixed charges."[16] Does RUCO agree?

A. RUCO doesn't dispute the notion that there are customer-related costs, nor that this concept was conceived of long ago. RUCO agrees that recovery of a *limited set* of customer-specific costs through a fixed charge can be justified. However, we disagree with the Company about the extent of fixed costs that should be

[16] Ibid, line 18

attributed to a single customer, versus costs that are commonly shared among multiple customers, and which should not be recovered through fixed charges.

b. Matching costs and rates

Q. What rationale does the Company give for the use of fixed charges to recover fixed costs?

A. Witness Overcast states that "It is only through the use of fixed charges to recover fixed costs that the matching principle of rates is satisfied.[17]" Elsewhere, Overcast states that the matching principle "provides that the rates charged should match the costs for all customers."[18]

Q. What does the American Public Power Association say about matching rates and costs?

A. In a recent paper, APPA states that "No rate design will perfectly match costs and rates."[19] RUCO agrees with this statement.

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[17] Ibid, p 30, line 7
[18] Ibid, p 19, line 10
[19] http://www.publicpower.org/files/PDFs/Rate_Design_for_DG-_Net_Metering_final.pdf

Q. Does RUCO agree that the matching principle suggests that all fixed costs should be recovered through fixed charges?

A. Not at all. Others have defined this principle as follows: “matching revenues with related expenses and investments in the time period they occur.”[20] In many applications of the matching principle, the overarching concern is whether revenues collected match the costs incurred over a specific period of time, without particular consideration of the design of rates used to collect those revenues.

Q. What would be the implications of perfectly matching costs with rates for individual customers?

A. In theory, if each individual customer was charged a set of rates that perfectly matched costs, customers would experience real-time energy rates that fluctuate minute by minute to recover marginal fuel and operating costs. They would also experience a real-time demand rate to recover system generation costs which would be very high in summer peak hours and very low in the winter. They would also experience a real-time demand rate that was unique to their local distribution system. Finally, they would experience a customer charge that was unique to each individual customer and would reflect the specific costs of metering, billing, and the service drop for that customer. Any averaging of customer charges would violate the matching principle as there would undoubtedly be variations in the exact cost of the service drop and customer meter.

[20] http://www.aarp.org/content/dam/aarp/aarp_foundation/2012-06/increasing-use-of-surcharges-on-consumer-utility-bills-aarp.pdf

Q. Does TEP's proposal accomplish this?

A. No.

Q. Can you provide an example of how the Company's proposal to include distribution system costs in the customer charge (other than the service drop and customer meter) would violate the matching principle?

A. Yes. Under the Company's proposal, if a new housing development were constructed in the Company's service territory, new distribution system costs (other than the service drop and customer meter) would undoubtedly be incurred, some of which would be classified by the Company as customer-related costs. This means that existing customers would pay higher customer charges, despite not having incurred those costs.

Q. Does the minimum system method violate the matching principle?

A. Yes. By collecting revenue for demand related costs in the customer charge, the rates that result violate the matching principle. By contrast, the basic customer method limits the customer charge to a narrower set of costs that can be attributed to the customer with a greater degree of certainty and precision.

c. Use of volumetric rates to recover fixed costs

Q. Does witness Overcast's example on p. 31 successfully prove that it is "not logical" to use kWh charges to recover fixed costs?

A. No. Witness Overcast's example is flawed because it presumes that all fixed costs (including generation, transmission, and distribution) are customer-related and caused by individual customers. As a counter example, consider the same system, with two customers. Let's assume that a third customer is added to the system one year later, but the existing generation, transmission, and distribution infrastructure is sufficient to serve all three. No additional generation, transmission, or distribution costs are imposed on the system, and therefore the third customer is not a cost causer for these categories. In this case the only new fixed costs imposed would be costs to connect the new customer to the system (e.g. service drop and customer meter). If the fixed costs of generation, transmission, and distribution were recovered solely through a fixed customer charges there is no way to avoid the following dilemma: either the third customer pays nothing (which is unfair), or all three pay a fixed charge (which violates the principle of cost causation). In this case, a kWh charge is both fair and logical, since it better reflects each customer's use of the shared assets, and thus the benefits received.

Q. What does the Company say regarding the benefits received principle RUCO raised in its testimony?

A. Dr. Overcast claims that "the benefits received argument has no basis for setting rates."[21] On the contrary, the principle of "beneficiary pays" has been used extensively as a basis for allocating costs of shared network assets.

Q. Where has this principle been used?

A. The Federal Energy Regulatory Commission (FERC) has adopted a "beneficiaries pay" approach for years to allocate costs of shared transmission network assets. As it has stated, "The cost of transmission facilities must be allocated ... in a manner that is at least roughly commensurate with estimated benefits.[22]" The courts have also upheld this approach as an extension of the principle of cost causation: "To the extent a [customer] benefits from the costs of new facilities, it can be said to have 'caused' a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed."[23] As FERC's example demonstrates, there is clearly a basis for considering benefits received as a consideration in the formulation of rates to recover shared network infrastructure. This aligns with the approach of recovering fixed costs through volumetric rates since kWh consumed can be seen as "roughly commensurate" with benefits received.

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[21] Overcast, p 37, line 21
[22] FERC. (2010). Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Docket No. RM10-23-000, June 17, 2010.
[23] Illinois Commerce Commission v. FERC, 576 F.3d 470, 476 (7th Cir. 2009).

d. Economic theories of efficient rates

Q. Setting aside other factors that must be considered, what does this theory tell us about setting economically efficient prices?

A. Economics would tell us that the best way to set efficient prices is to allow the free market to do so. In fact, price regulation of utilities is intended to be a "second best" alternative to competition in the case of a natural monopoly. If we turn to free market as a guide, we can easily observe plenty of examples of products and services with high fixed costs that don't have fixed charges. If competition can provide regulators with any insight into efficient price formation, it is that there are no hard and fast rules about fixed costs and fixed charges. Gasoline is just one example that RUCO offered in its direct testimony but there are many others (e.g. per hour rentals, transportation services, etc). As witness Jones pointed out, and RUCO also acknowledges, there are differences in how the petroleum industry operate compared to electric utilities. Some of these factors (e.g. obligation to serve) may even compel a certain pricing regime for utilities, however, it's not readily apparent that high fixed costs is one of those factors

Q. What is the potential role of fixed charges in terms of encouraging economically efficient customer decisions?

A. A major purpose of efficient pricing is to send price signals that consumers can interpret and respond to, based on their individual preferences. However, the only customer decision that could possibly be influenced by a fixed customer charge is whether or not to connect to the system. Thus a fixed customer charge that includes more than the marginal cost to connect to the system is by definition inefficient.

Q. What does witness Overcast say regarding the theory of efficient rates?

A. Dr. Overcast states that utilities are a "declining cost industry" and that "[u]nder the economic theory of optimal rates, the customer charge would be higher than the TEP proposed customer charge and higher even than the allocated customer costs because *marginal costs are low*."[24] (emphasis added).

Q. What does witness Jones say regarding marginal costs?

A. Jones' direct testimony includes the Company's Cost of Service Study, and reports that that marginal customer costs are *higher than* embedded costs ($29.49 per month versus $15.67 per month). As he states, "the depreciated original cost for these assets is far below the replacement cost for these assets."[25]

Q. What is RUCO's view of these statements?

A. The statements appear to be inconsistent. On the one hand, witness Overcast suggests that a higher fixed charge is partly justified due to high embedded costs and low marginal costs. On the other hand, witness Jones demonstrates the opposite -- that embedded customer costs are actually lower than marginal costs.

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[24] Ibid, p 30, line 19.
[25] Jones, p 31, line 15.

4. Recent fixed charge proposals

Q. How many utilities does Dr. Overcast claim have customer charges over $20 per month?

A. Dr. Overcast claims that "there are about 1000 electric utilities with residential customer charges above $20 per month."[26] This is apparently based on data from OpenEI Utility Rate Database, which is cited in Dr. Overcast's testimony.

Q. Does RUCO have any concerns about the OpenEI Utility Rate Database?

A. Yes, I have major concerns. Many of the utility rates included in the OpenEI Utility Rate Database, cited by Overcast, are commercial, general service, or multi-family rates -- not residential rates as Overcast claims. Moreover, some rates have been closed for 20 years (despite being listed as open in the database). Other rates included in this dataset apply to mountain top service, grain-drying operations, farms, cotton gins, grain bins, RV parks, master-metered apartments, and other situations that are not single family residences. Additionally, the database includes multiple rates for the same utility, leading to a strong possibility for over counting.

Q. Upon review of the OpenEI data, are you able to accurately discern how many utilities' have customer charges above $20 per month?

A. No. It is my opinion the OpenEI database cannot be relied upon to determine the number of utilities with residential fixed customer charges above $20 per month

[26] Overcast Rebuttal Testimony at p. 32, line 14

for single-family residences due to the above mentioned integrity and categorization issues.

Q. How many utilities does Overcast claim are increasing fixed charges?

A. Dr. Overcast claims there are "literally thousands of utilities"[27] that are increasing customer charges.

Q. Is any evidence presented to support this claim?

A. No. Dr. Overcast does not provide any further details to indicate precisely how many or which utilities have adopted these increases in recent years. Moreover, he does not indicate which rate classes the charges apply to, whether these increases have been approved for implementation or merely proposed, or the magnitude of the increases being proposed or implemented.

Q. What other data might indicate how many utilities are increasing fixed charges for their residential customers?

A. According to a recent report, thirty seven utility proposals for increased residential fixed charges were decided in 2015. Sixteen of these decisions failed to approve *any* increase in fixed charges.[28] These numbers demonstrate that there are far

[27] Ibid. p. 31 line 23
[28] North Carolina Clean Energy Technology Center & Meister Consultants Group, The 50 States of Solar: 2015 Policy Review and Q4 Quarterly Report, February 2016.

fewer utilities implementing increased fixed charges than the "literally thousands" claimed by Dr. Overcast.

Q. Are there other relevant points from these reports you would like to include?

A. Yes. The NC Clean Energy Technology Center 50 States of Solar 2015 Policy Review includes several takeaways regarding fixed charges as they apply to all customers (including non-solar customers). Of the 37 fixed charge decisions that were decided in 2015, the median initial fixed charge for these utilities was $8.89 per month and the median proposed fixed charge was $17.25 per month. In nearly half of the cases (16 cases) no increases in fixed charges were approved. The approved fixed charges raised the median to $10.85 per month, an increase of $1.85 per month.[29] The Company's proposed fixed charge increase is not in line with previous decisions.

5. <u>Concerns regarding increased fixed charges</u>

Q. In its testimony, RUCO listed several potential concerns others have raised regarding the negative impact of increased fixed charges. Did the Company respond to these points?

A. Yes. Witness Overcast argued that these concerns were "not valid." However, RUCO did not find any of the arguments persuasive. I will elaborate on each response, and explain why the concerns listed are in fact still valid.

[29] North Carolina Clean Energy Technology Center & Meister Consultants Group, The 50 States of Solar: 2015 Policy Review and Q4 Quarterly Report, February 2016

a. Control over customer bills

Q. What did the Company say regarding the concern that customers' control over their bills will be reduced under a higher fixed charge?

A. Witness Overcast states that "the proposed rates still provide the customer control over the bill unless the customer uses zero kWh."

While it is true that most customers would still have some control over a portion of their bill, RUCO believes this concern is still valid since the degree of customer control is substantially reduced under a higher fixed charge. What is important to recognize is that the higher the fixed charge, the greater share of the overall revenue requirement is collected through this mechanism. By necessity, this means that a smaller share of overall revenue is collected through volumetric rates, and in turn volumetric rates would be relatively lower than if the fixed charge were held constant. Thus, the higher the fixed charge component of the rate, the smaller the bill reduction will be from actions pursued by a customer to reduce their consumption.

b. Rate shock

Q. Did RUCO's testimony argue the proposed rates would lead to 'Rate Shock'?

A. No. Contrary to what Dr. Overcast insinuates, RUCO did not invoke the term "rate shock" to describe the Company's proposed rates. It appears Dr. Overcast jumped to this conclusion. The term was included in RUCO's direct testimony as one reason why some similar fixed charge proposals may have been denied or scaled back in other jurisdictions.[30]

Q. Please address Dr. Overcast's concerns regarding rate shock.

A. Despite not using the term to refer to the Company's proposed rates, RUCO would like to take the opportunity to refute the rate shock argument as presented by Dr. Overcast. The $0.33 per day presented in Overcast's testimony represents an increase of $120 per year[31]. RUCO understands the $0.33 per day is an average increase for all customers and some customers, particularly lower income customers, may be disproportionately affected by a daily increase above $0.33 per day. This is not an insignificant increase particularly for customers on fixed incomes. Additionally, low use customers (<500 kWh) would be subject to an average percentage rate increase that is more than twice as large as high use customers (>3500 kWh).

c. Low-income customers

Q. Are there any other groups that support RUCO's claim that low-income customers use less energy than higher-income customers?

A. Yes. Included in The National Association of State Consumer Advocates 2015-1 resolution;

[30] Direct Testimony of Lon Huber, p. 13 line 4
[31] Overcast Rebuttal Testimony p. 33 line 22

"data collected by the U.S. Energy Information Administration show that in a vast majority of regions called "reportable domains," low-income customers (with incomes at or below 150% of the federal poverty level) on average use less electricity than the statewide residential average and less than their higher-income counterparts."[32]

This resolution was included in RUCO's direct testimony.

Q. Dr. Overcast argues that there is "little or no correlation between low usage and poverty levels."[33] Does the evidence support this assertion for TEP?

A. Not necessarily. While some studies have shown that low-income does not imply low consumption in some parts of U.S., there is also evidence to suggest that this may not be true in the West. According to one recent study, low-income customers in three western utilities had usage 17%-27% lower than non-low-income customers, while results in the Midwest and East were mixed[34]. This study attributes this disparity to "differences in housing stock and reliance on energy-intensive heating and cooling units."

Q. Does this mean all low use customers are low-income customers?

A. No. RUCO acknowledges that some low usage customers may not necessarily be lower income, particularly those that seasonally occupy their homes. However,

[32] https://nasuca.org/customer-charge-resolution-2015-1/
[33] Overcast, p 24, line 20
[34] http://aceee.org/files/proceedings/2014/data/papers/7-287.pdf

for reasons explained above, RUCO believes the Commission should proceed with extreme caution when considering rate design options that could disproportionately affect low-use customers, since they could also disproportionately affect low-income customers.

d. Low usage customers

Q. How can TEP fairly recover fixed costs from low usage customers that are not also low-income customers?

A. Many homes in the Tucson area are only seasonally occupied during the winter. These customers are away from the Tucson area during summer and do not contribute to summer season peak, but also contribute less to overall recovery of fixed costs.

A seasonal rate option for certain low use customers that are not low-income may be able to help ensure fair recovery of costs without jeopardizing low-income customers. Several other utilities have a seasonal use rate that provides a minimum bill during times when a home may be unoccupied. Under this option, customers would aid in fixed cost recovery in a manner that is more aligned with year round customers. This approach would also be compatible with targeted assistance programs for low-income customers.

e. Efficiency and price signals

Q. Does RUCO believe that energy efficiency and price signals are the same issue as witness Overcast asserts?

A. Not necessarily. There are two distinct price signals to consider: one is the price signal that is sent by a fixed charge itself as one component of the overall rate design. The other is the price signal sent by the remaining volumetric component, which encourages reduced consumption and investment in energy efficiency.

Q. Does RUCO have any concerns with the Company's discussion of energy efficiency and price signals?

A. Yes. Overcast states that "[b]y charging rates that exceed marginal cost ... the RUCO proposal is supporting a significant loss in social welfare.[35]" Crucially, however, witness Overcast's testimony lacks specificity when discussing what constitutes marginal costs and whether these are short run or long run costs. Long run marginal costs (i.e. including investments in new generation capacity) tend to be significantly higher than short run marginal costs (i.e. fuel costs). Thus, there is ample justification to set volumetric rates that are high since that will encourage customers to reduce consumption, providing positive social benefits both in the form of avoided energy and in avoided capital investments. In contrast, there are virtually no beneficial actions that would be encouraged by a higher fixed charge.

[35] Overcast, p 35, line 15

The challenge for regulation is that there is no perfect way to recover embedded fixed costs. Regulators may have some discretion to choose whether to incorporate these costs in fixed rates or volumetric rates. However, for reasons stated above, and elsewhere in this testimony, RUCO believes there are far more reasons why volumetric rates should be preferred.

Q. What does witness Jones's rebuttal testimony say regarding higher fixed charges?

A. Jones implies that various intervenors are incorrect in claiming that "increasing the fixed charge … will lead customers to use more power."[36]

Q. Does RUCO agree?

A. No. There is no question that a fixed charge component, on its own, provides no incentive for customers to reduce consumption. Moreover, if more of the revenue requirement is allocated to and recovered through fixed customer charges, the less revenue is allocated to and recovered through other rate components that customers can control. As a result, customers will have less incentive to reduce consumption and will be likely to consume more.

[36] Jones, p 35, line 14.

6. Earnings Risk

Q. What does the Company say regarding the impact of the increased fixed charge on earnings risk?

A. The Company confirmed the general notion that rate design and earnings risk are linked. For example, the Company states that if kWh usage is reduced from the current pattern, then "system earnings will decline more than currently"[37] illustrating the link between volumetric rates and earnings risk. Additionally, witness Overcast provides the following quote: "An access charge reduces the risks of recovering residual utility embedded costs, provides greater revenue stability on existing assets for utilities, limits uneconomic bypass, and should allow utilities to achieve lower financing costs of the network on behalf of all ratepayers."[38]

RUCO estimates that under the company's original proposal, the portion of margin revenues derived from residential customers through fixed charges would increase from about 17% to about 27%[39]. Given that there is less risk inherent in revenue collected from customer charges, RUCO believes there is ample justification for

[37] Ibid, p 38, line 20
[38] Ibid, p 35, line 6.
[39] According to Schedule H-2 of the Company's testimony, there would be 4.6 million residential basic service charges assessed annually. Thus an increase from $10 to $20 represents an increase in revenue from $46M (17% of the $277M in test year margin revenues from residential) to $92M (27% of the $341M proposed margin revenues from residential).

an ROE adjustment if the Company's proposal were adopted, without the need for comparison to other companies.

7. Tiered Rates

Q. Does RUCO have any concerns regarding Jones' interpretation of any of RUCO's testimony?

A. Yes. Jones misinterprets the purpose of the table on page 26 of RUCO's testimony. RUCO agrees with Jones's general argument that customers are primarily concerned about overall bill reductions. In fact, the very purpose of this table was to illustrate the impact that changes to consumption would have on customer bills. In this context, it is the *marginal* rate that is most relevant for each group of customers, not the average rate. This is why RUCO chose to represent the marginal rate in its table.

Q. Why did RUCO choose to consider marginal rate over average rate?

A. Marginal rates are more appropriate than average rates when considering price signals and the ability for customers to control their bills and invest in more energy efficient appliances. Similarly, the marginal rate is what determines the increase in a customer's bill if they increase consumption, for example, during a hot summer. The table presented on page 26, of RUCO's testimony, accurately illustrates the change to the marginal rate that each group of customers will experience. Thus, the original conclusion remains valid; under the Company's proposal, higher tier users will have less incentive to reduce consumption. Meanwhile, any increase in consumption for lower tier users will lead to a larger bill increase.

Q. Why were non-fuel components used in the table?

A. It was RUCO's intent to focus on the non-fuel components since the company has greater flexibility in what rates it proposes and ultimately uses to collect these costs.

Q. Mr. Jones observed that "mandating that all customers of a certain size be moved to this rate seems contradictory to RUCO's opposition of mandatory three-part rates for new DG customers." Do you agree with this characterization?

A. No. RUCO is suggesting a default TOU rate, not a single mandatory rate plan for large residential customers.

Q. Could there be implementation issues with transferring larger users to a default TOU?

A. No one said modernizing rates is easy, especially when dealing with legacy technology. RUCO does not propose TEP make this transfer right out of the gate. Once education efforts are in place, technology rollouts are near complete, etc. only then should this be done. The implementation hurdles are not insurmountable.

Overcoming them is necessary if we want smarter rates that benefit both ratepayers and the utility.

Q. Does this conclude your testimony?

A. Yes.