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BEFORE THE ARIZONA CORPORATION COMMISSION

AZ CORP COMMISSION
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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 **NOTICE OF FILING REBUTTAL TESTIMONY**

Tucson Electric Power Company ("TEP"), through undersigned counsel, submits the Rebuttal Testimony of David G. Hutchens, Susan M. Gray, Kentton C. Grant, Ann E. Bulkley, Frank P. Marino, David J. Lewis, Michael E. Sheehan, Ramondo J. Robey, Mark C. Mansfield, Carmine Tilghman, Dallas J. Dukes, H. Edwin Overcast, Craig A. Jones, Richard D. Bachmeier and Denise A. Smith.

RESPECTFULLY SUBMITTED this 25th day of July 2016.

Arizona Corporation Commission
DOCKETED
JUL 25 2016
DOCKETED BY

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Rebuttal Testimony of

David G. Hutchens

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IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD IMPLEMENTATION PLAN.	DOCKET NO. E-1933A-15-0239
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REBUTTAL TESTIMONY OF

DAVID G. HUTCHENS

ON BEHALF OF

OF TUCSON ELECTRIC POWER COMPANY

JULY 25, 2016

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is David G. Hutchens and my business address is 88 East Broadway, Tucson, Arizona, 85702.

Q. Did you file Direct Testimony in this proceeding?

A. Yes.

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. My Rebuttal Testimony is filed on behalf of Tucson Electric Power Company ("TEP" or the "Company").

Q. How is your Rebuttal Testimony organized?

A. First, I summarize the Company's response to the revenue requirement proposals set forth by parties in this case. Next, I provide a high level overview of TEP's revised request for a non-fuel revenue increase. I then respond to certain statements in RUCO witness Frank Radigan's testimony. Finally, I summarize certain of TEP's rate design proposals in this case, including proposed changes to the lost fixed cost recovery mechanism ("LFCR").

II. THE REVENUE REQUIREMENT PROPOSALS SET FORTH BY PARTIES IN THIS CASE WOULD HARM THE COMPANY'S FINANCIAL POSITION AND ARE NOT IN THE PUBLIC INTEREST.

Q. Please summarize TEP's proposed increase in non-fuel revenues?

A. In the Company's application, TEP requested a non-fuel revenue increase of $109.5 million.

Q. What are the key factors contributing to TEP's requested increase in non-fuel revenues?

A. As I stated in my Direct Testimony, the primary factors contributing to the Company's request for an increase in non-fuel revenues include the recovery of costs and investments related to (i) TEP's ongoing efforts to diversify its resource portfolio and (ii) infrastructure investments that updated and reinforced the facilities that support safe and reliable service.[1] Another factor necessitating new rates is the decline in the Company's sales levels. During the 12 months ended June 30, 2015 (the test year used in this case), TEP's retail sales were nearly 3% below the level from December 31, 2011 (the test year from the prior rate case).[2] As a result of the lower sales volumes, TEP's new rates must be designed to recover its fixed costs over fewer kilowatt hours (kWh).

Q. Please summarize the increase in non-fuel revenues proposed by the parties in this proceeding.

A. Staff, RUCO, AECC and DOD recommend non-fuel revenue increases that are substantially below the level requested by TEP. For example, RUCO recommends an increase in non-fuel revenues that is 84% below TEP's request. That proposal, if

[1] Direct Testimony of David Hutchens, pages 4:8-9, 5:17-20, 7:1-27, 8:1-7.
[2] Direct Testimony of David Hutchens, page 10:3-4.

approved, could substantially harm TEP's financial position and would force the Company to file another rate case almost immediately. In addition, a period of prolonged under-recovery of costs and investments would begin to impair TEP's ability to provide safe and reliable services to its customers. These outcomes would not serve the public interest or the best long-term interests of our customers. The non-fuel revenue requirement proposals by Staff, RUCO, AECC and DOD are summarized below.

	Staff	**RUCO**	**AECC**	**DOD**
Non-Fuel Revenue Increase	$49.4 million[3]	$17.4 million[4]	$60.9 million[5]	$76.0 million[6]
Reduction from Company's Proposal in Direct Testimony	$60.1 million or 55%	$92.1 million or 84%	$48.6 million[7] or 44%	$33.5 million or 31%

Q. Please explain how the non-fuel revenue increases proposed by parties in this case would harm TEP's financial position.

A. TEP currently enjoys a solid investment grade rating of A3 from Moody's Investor Services ("Moody's") and BBB+ from Standard & Poor's. These ratings allow TEP to access the capital markets on favorable terms and result in direct savings for customers through lower interest rates on debt financing. TEP's rate request reflects a weighted average cost of debt of 4.32%. This is significantly lower than the 5.18% that was approved in TEP's last case, as explained in the Direct Testimony of Kentton C. Grant.

> These improved credit ratings are more in line with industry-wide credit ratings, and provide the Company with access to capital on

[3] Direct Revenue Requirement Testimony of Staff Witness Mullinax, page 6:20.
[4] Direct Revenue Requirement Testimony of RUCO Witness Michlik, page 4:14.
[5] Calculated by Company based on AECC's proposed revenue reduction.
[6] Direct Revenue Requirement Testimony of DOD Witness Gorman, Exhibit MPG-1.
[7] Direct Revenue Requirement Testimony of AECC Witness Higgins, page 7:11.

> more reasonable terms. Credit ratings have a huge impact on the perceived creditworthiness of the Company...As a capital intensive business, TEP must access the debt markets on a regular basis to finance a portion of its capital expenditures...in 2015, TEP issued $300 million of new 10-year bonds at a fixed rate of 3.05%. The interest rate of 3.05% was the lowest rate realized by TEP in over four decades on an issuances of fixed-rate long-term debt....the resulting interest savings will now be passed onto customers through a lower weighted average cost of debt.[8]

A fundamental regulatory principle is that rates should be designed so a utility recovers its prudently incurred costs and is provided an opportunity to earn an appropriate return on its rate base investments. The rates proposed by parties in this case, which include a variety of cost disallowances, fail this test. The Company's current non-fuel revenue deficiency is not sustainable over the long-run and would adversely impact the Company's credit ratings.

Q. Please elaborate on how these non-fuel revenue increase proposals could lead to a credit ratings downgrade.

A. The reduced non-fuel revenue increases proposed by Staff and other Intervenors would negatively affect the Company's earnings and cash flows, two financial measures that are heavily weighted in the credit rating review process.

According to a March 2016 Moody's credit opinion, the Company's current investment grade rating reflects "...the constructive Arizona regulatory environment that supports the company's credit profile, reduced regulatory lag associated with cost and investment recoveries and the expectation that projected financial metrics will remain steady."

The report also contains factors that could lead to a downgrade of TEP's credit rating: "TEP's rating could be downgraded if a more contentious regulatory environment in Arizona re-emerges, which results in a deterioration in the credit supportiveness of the

[8] Direct Testimony of Kentton Grant, pages 6:25-27, 7:26-27, 8:1-2, 8-12.

regulatory framework including greater regulatory lag, contentious, litigated regulatory proceedings, higher uncertainties about the recovery of investments, further compression in rates (especially if accompanied by a rise in interest rates) or if financial metrics deteriorated."

Q. How would a lower credit rating impact customers?

A. A downgrade of TEP's credit ratings would lead to higher debt costs, increased financial risk, a higher return on equity ("ROE") and, ultimately, higher costs passed onto customers in future rate cases.

Q. Would such a deterioration of TEP's credit ratings and financial condition be consistent with prior Commission orders?

A. No, not at all. Such a result would be inconsistent with prior Commission orders, such as the 2014 Fortis Merger Order[9] and the 2016 TEP Financing Order[10], both of which encourage the Company to either maintain or improve its financial integrity.

[9] Decision No. 74689 (August 12, 2014).
[10] Decision No. 75414 (January 19, 2016).

III. THE COMPANY'S REVISED NON-FUEL REVENUE REQUIREMENT REQUEST.

Q. Is TEP reducing its requested non-fuel revenue increase?

A. Yes. In the spirit of compromise, the Company is revising its requested non-fuel revenue increase to $100.6 million, a reduction of approximately $9 million from its initial request.

Moreover, TEP's overall rate request actually has been reduced even further because the non-fuel rate increase now includes $15 million of Springerville Unit 1 ("SGS Unit 1") costs previously proposed for recovery through the Company's purchased power and fuel adjustment clause ("PPFAC"). Absent this revenue-neutral rate adjustment, TEP's non-fuel rate request is now $24 million (or 22%) lower than requested in the Company's Application. This reduction was achieved by making the following concessions:

- reducing its requested return on equity ("ROE") from 10.35% to 10.00%;
- increasing the percentage of generation costs allocable to wholesale jurisdictional sales; and
- accepting certain pro forma expense adjustments proposed by Staff and RUCO.

The Company's revised revenue requirement and related components are explained in more detail in the Rebuttal Testimonies of Kentton C. Grant, Ann E. Bulkley, Frank P. Marino, Dallas J. Dukes, David J. Lewis, and Michael E. Sheehan.

Q. Why is it important that non-fuel O&M costs (including property taxes) related to 50.5% of SGS Unit 1 be reflected in rates?

A. As described in the Rebuttal Testimony of Kentton C. Grant, TEP now expects to own all of SGS Unit 1 before the effective date of an order in this case. While the Company is not yet seeking to include the purchase price in rate base, it is critical that TEP begin recovering the non-fuel operating costs of SGS Unit 1 through rates since the plant will be providing power to our retail customers. TEP will not seek rate base treatment of its purchase of the 50.5% of SGS Unit 1 until its next rate case.

Q. Please describe the importance of owning 100% of SGS Unit 1.

A. TEP's long-term commitment to SGS Unit 1 is in the public interest. As described in more detail in the Rebuttal Testimony of Michael E. Sheehan, a third-party economic analysis of SGS Unit 1 concluded that ownership of 100% of SGS Unit 1 provides our customers with long-term rate stability due to reduced exposure to natural gas commodity risk and reduced commitments to capital investments over the near-term. TEP's ownership of SGS Unit 1 also provides much-needed economic stability and certainty to several small communities that surround the Springerville Generating Station ("SGS") in Apache County. A September 2014 study published by Arizona State University quantified the following economic impacts of SGS:

- 332 jobs;
- $450 million in contributions to gross state product;
- $46 million of total compensation; and
- $22 million of state, county and local taxes.

TEP views both SGS Units 1 and 2 as key components of our long-term energy resource plan. In fact, we currently estimate that by 2032 these plants will be the only coal-fired generating resources remaining in TEP's energy portfolio. SGS Units 1 and 2 are well run,

low-cost base load generating resources that should provide our customers with safe and reliable electricity for decades.

IV. RESPONSE TO RUCO WITNESS FRANK RADIGAN.

Q. Would you like to respond to any statements made in the testimony of RUCO witness Frank Radigan?

A. Yes. When commenting on the increase in TEP's rate base from its last rate filing to the current filing, RUCO witness Radigan states the following:

> ...Company President David Hutchens states that from the period of January 1, 2012 to June 30, 2015, TEP invested approximately $1.3 billion in order to continue providing customers with safe and reliable service. On a net plant basis for retail customers these investments increase rate base from $1.5 billion in the last case to $2.1 billion in this case an increase of 40%. The Company does not seem to understand its building for load that under current market conditions is unlikely to return.[11]

Q. Do you agree with Mr. Radigan's comment regarding the need for such investments?

A. No, not at all. To the contrary, Mr. Radigan does not seem to understand that TEP is making decisions and investments that are in the best *long-term* interests of our customers, a principle we believe RUCO shares in its advocacy on behalf of residential customers.

Q. Is the increase in TEP's rate base over the last four years primarily attributable to load growth in the Company's service territory?

A. No. As I noted earlier and in my Direct Testimony, the increase in TEP's rate base from the last rate case is primarily a result of investments made to (i) diversify TEP's resource portfolio; (ii) update and reinforce the utility system to account for, among other things,

[11] Direct Revenue Requirement Testimony of RUCO Witness Radigan, pages 5:23, 6:1-7.

the addition of approximately 10,000 new customers; and (iii) continue to provide safe and reliable service to our customers.

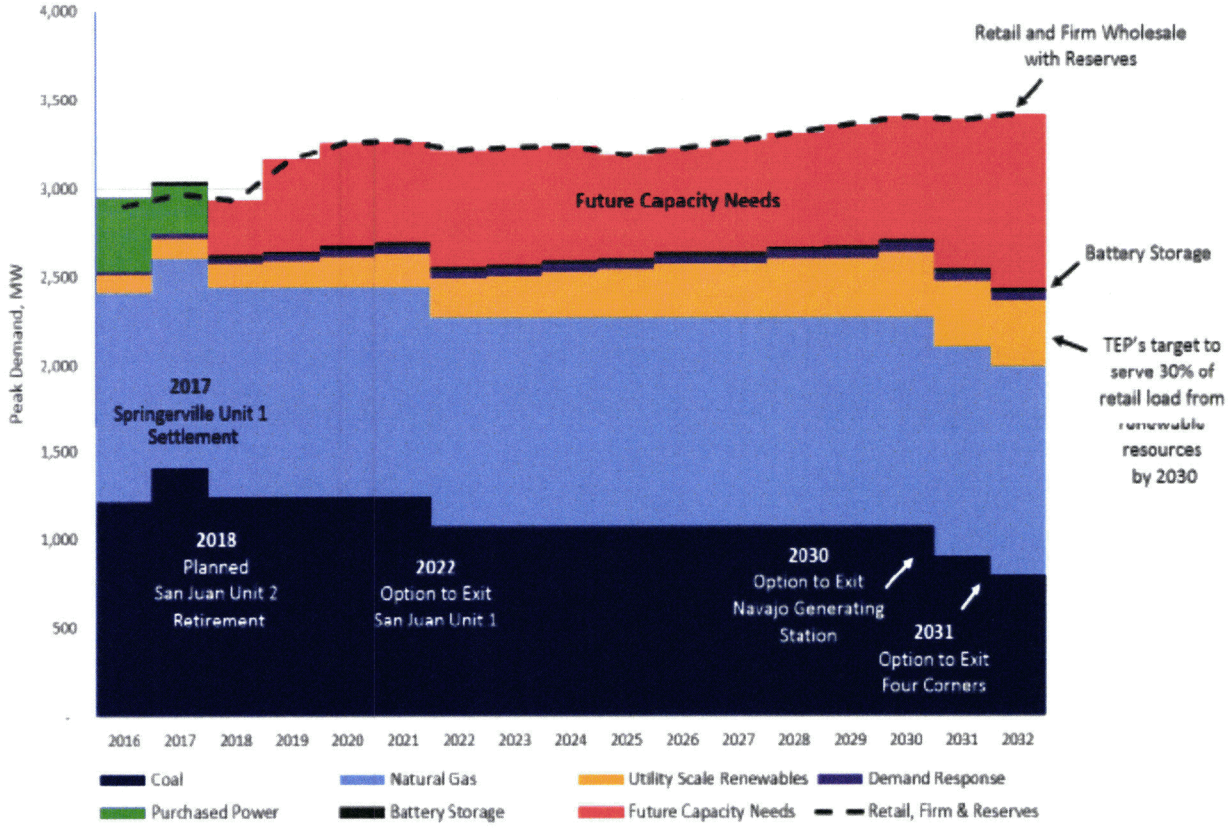
Q. Please explain the rate base growth driven by TEP's resource diversification plan.

A. TEP's proposed rates reflect the first steps of a resource diversification strategy that will take many years to fully execute, including: (i) the acquisition of Gila River Unit 3 at a very favorable price; (ii) the addition of utility-scale solar resources that support cost-effective compliance with the Renewable Energy Standard; (iii) the permanent conversion of a local coal-fired generating unit to burn only natural gas; and (iv) the retirement of a coal-fired facility in New Mexico. It is important to note that all of the unrecovered costs associated with items (iii) and (iv) are being entirely offset by excess depreciation reserves and therefore have no impact on rates.[12]

The chart below, taken from the Company's 2016 preliminary integrated resource plan ("IRP")[13], shows our initial assessment of TEP's forecasted loads and resources from 2016 – 2032.

[12] Direct Testimony of Frank P. Marino, page 12:13-16.
[13] Filed with the Commission on March 1, 2016 (Docket No. E-00000V-15-0094).

Chart 8 – TEP's 2016 Preliminary Loads and Resource Assessment



Q. Please explain how TEP's resource diversification plan is in the public interest.

A. The coal plants in TEP's generating fleet are subject to various federal environmental regulations that require either (i) expensive emission control modifications or (ii) closure of the facility.[14] Continuing to rely on coal as a primary fuel source is just not a viable long-run strategy for our Company or our customers. I firmly believe that TEP is taking gradual, well-planned, cost-effective steps to reduce its reliance on coal as a primary fuel source while still providing safe, reliable and affordable energy to our customers. Choosing to ignore current and pending environmental regulations affecting the Company's coal-fired generating facilities is simply not an option and is certainly not in the public interest. As I stated in my Direct Testimony:

[14] Please see the Direct Testimony of Company Witness Michael E. Sheehan.

> TEP has been working for many years to diversify its generation portfolio, including reducing its reliance on coal-fired generation, expanding its use of renewable energy resources and promoting cost-effective EE...These decisions will preserve TEP's access to reliable, cost-effective base-load resources in the face of coal plant retirements and other impacts that may result from Environmental Protection Agency ("EPA") enforcement of new rules regulating CO_2 emissions from power plants ("the Clean Power Plan") and other new emission limits.[15]
>
> TEP is executing a portfolio diversification strategy that will reduce the risks associated with investments in coal-fired generation and increase reliance on zero-carbon resources such as utility-scale renewable energy and energy efficiency.[16]

Q. You said the increase in TEP's rate base also reflects investments made to update and reinforce TEP's utility system. Please explain.

A. TEP continuously monitors and evaluates its distribution system to ensure that customers are receiving safe and reliable service. In my Direct Testimony, I noted that TEP made over $250 million of distribution system investments related to system reinforcement, growth for new business, public improvement projects, substation construction and maintenance, and the replacement of aging infrastructure.[17] Company witness Susan M. Gray addresses this in more detail in her Direct and Rebuttal Testimonies.

Q. How do these investments to update and reinforce TEP's utility system affect safety and reliability?

A. Providing safe and reliable service is the principal focus of our business. We strive to perform all of our work in a manner that prevents injury to ourselves, our co-workers, our customers or any other member of the community who may come in contact with us or our equipment. Likewise, we strive to maintain consistent service reliability for our customers.

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[15] Direct Testimony of David Hutchens, pages 5:17-20, 8:4-7.
[16] Direct Testimony of David Hutchens, page 13:18-20.
[17] Direct Testimony of David Hutchens, page 27: 8-11.

Susan M. Gray describes the distribution system planning process and provides several examples of the investments TEP makes to ensure that customers receive the high level of service reliability that they expect. On average, a TEP customers experiences less than one outage per year and the duration that outage is approximately one hour.

Q. Mr. Radigan states in testimony, "Based on my review of the transmission and distribution system, I am fearful that this build out of the system in hopeful anticipation for historic load growth is continuing."[18] Do you have a response?

A. Yes, I do. Nowhere in the Company's Direct Testimony does it state that TEP is building out the system in anticipation of historic load growth continuing, nor are we doing so. Mr. Radigan's testimony fails to recognize that TEP has an obligation to provide safe and reliable service to its customers. This means that TEP's system must reach every one of the 417,000 customers in its service area and be capable of meeting the instantaneous peak load of every one of those customers, regardless of when their peak occurs.

Q. In your opinion, does Mr. Radigan's testimony confuse the difference between energy sales and peak system demand?

A. Yes. Energy sales and peak system demand are two very different concepts. Energy sales reflect the volume of electricity our customers consume over a specific period of time, measured in kilowatt hours ("kWh"). Peak demand, measured in kilowatts ("kW"), represents a customer's maximum "pull" of energy during a given period. Volumetric energy consumption and demand aren't necessarily correlated. For example, consider two customers, each billed for 900 kWh of consumption during a given month. While their sales levels were identical, one of them works from home and uses electricity fairly constantly throughout the month, placing a relatively low demand on TEP's system. The other customer comes home from work at 5 p.m., starts cooling his home with two air

[18] Direct Revenue Requirement Testimony of RUCO Witness Radigan, page 26:6-8.

conditioners and begins simultaneously cooking and doing his laundry, imposing far greater demand on the Company's facilities during a period of peak system utilization. TEP must build and maintain its system to meet peak demand, not volumetric energy consumption – a point that cannot be stressed enough.

Q. Did Mr. Radigan testify on behalf of RUCO in TEP's last rate case?[19]

A. Yes, he did. In fact, as he has done in this matter, he initially took a very extreme position by proposing to disallow a significant amount of the Company's used and useful rate base.[20]

Q. Was TEP's last rate case resolved by a settlement agreement?

A. Yes. The settlement agreement ("2013 Settlement Agreement") that was approved in Decision No. 73912 (June 27, 2013).

Q. Was RUCO a signatory to the 2013 Settlement Agreement?

A. Yes.

Q. Were any of Mr. Radigan's rate base proposals approved as part of the 2013 Settlement Agreement?

A. No. However, the 2013 Settlement Agreement does contain a provision that requires TEP to meet with both RUCO and Staff annually to discuss the Company's capital expenditures for distribution plant. Section 20.4 states the following:

> Capital Expenditures for Distribution Plant: TEP agrees to meet with RUCO and Staff once a year for the next 3 years to discuss TEP's capital expenditures, planning horizons, and related planning (reconciled with TEP's IRP) for the upcoming year. TEP

[19] Docket No. E-01933A-12-0291.

[20] Radigan Direct Testimony (Docket No. E-01933A-12-0291), page 7:19-22. Mr. Radigan subsequently updated his rate base proposal in supplemental testimony in that docket.

> will provide the capital expenditure details and supporting information at least one week prior to the scheduled meeting.

Q. Has TEP complied with this provision of the 2013 Settlement Agreement?

A. Yes. TEP met with RUCO and Staff on December 1, 2014 and December 2, 2015 to discuss plans for distribution system investments as required by the 2013 Settlement Agreement. We also discussed plans for investments across our entire utility system, including generation and transmission assets.

Q. Was Mr. Radigan present at either of these meetings?

A. No, not to my knowledge. I did not personally attend these meetings, but I have been briefed by the employees that attended on behalf of the Company.

Q. Please briefly comment on the content of those presentations.

A. Both presentations followed a similar format. On the first page, the Company describes the key drivers behind its capital expenditure forecasts. These included: resource diversification; system reinforcement and reliability; existing maintenance of generation facilities; and technology and communications. The presentations also provided historic and forecasted capital expenditures. The 2015 presentation included additional detail on specific projects and initiatives.

Q. In your Direct Testimony, you describe the $1.3 billion of capital investments made in between rate cases and the correlation with the increase in the Company's rate base. Is this figure consistent with the information provided to Staff and RUCO in these meetings?

A. Yes. In fact, Staff witness McGarry stated the following in his Direct Testimony:

> According to the requirements of the settlement in E-01933A-12-0291, TEP agreed to meet annually with Staff to review the Company's actual capital spending and future plans for the

> upcoming year. Meetings with Staff were held in December 2014 and then again in December 2015. Information presentation in these meetings is consistent with what the Company has overall included for recovery in current rate base. I would recommend that these meetings continue as Staff has conveyed that they were useful in gaining a clearer picture of what the Company was planning for the upcoming years.[21]

Q. Do you agree with Staff that these meetings should continue?

A. Yes. I believe these meetings provide an excellent opportunity for the Company to keep Staff and RUCO updated on the Company's capital investment plans.

V. TEP'S RATE DESIGN, NET METERING AND TRACKER PROPOSALS ARE CRITICAL AND IN THE PUBLIC INTEREST.

Q. Is the Company revising any of its residential rate design proposals for non-DG customers?

A. Other than a modification to the proposed residential basic service charge, the Company is not proposing any significant changes to the rate design proposals set forth in TEP's Direct Testimony. For all non-DG residential customers, TEP proposes, among other things, to:

- Set the basic service charge at $17 per month as proposed by Staff.[22] While the Company believes its Direct Testimony fully supports a $20 monthly basic service charge, TEP is willing to accept Staff's position.
- Eliminate two of the four inclining volumetric tiers, as supported by Staff.[23]

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[21] Direct Revenue Requirement Testimony of Staff Witness McGarry, page 29:9-15.
[22] Direct Rate Design Testimony of Staff Witness Solganick, page 30:1.
[23] Direct Rate Design Testimony of Staff Witness Solganick, page 29:21-23.

- Offer optional three-part TOU demand rates, also supported by Staff[24] and RUCO.[25]

Q. Would you like to make any specific comments regarding Staff's rate design testimony?

A. Yes. The Company supports many of the principles of Staff's "Long-Term Rate Design Plan" contained in the testimony of Mr. Solganick. Specifically, TEP agrees with the following statements regarding the long-term migration of all customers to a single three-part TOU rate:[26]

- Rates should be based on costs derived from the class cost of service study.[27]
- Rate design should recognize the concepts of customer, demand and energy, and also recognize TOU and seasonality ("Three-Part TOU").[28]
- Generation pricing would reflect the market place by considering seasonality, TOU, hourly pricing and demand response.[29]
- Rates should be supported by customer-specific usage information collected under extreme privacy and security.[30]
- Rate subsidies should be clearly delineated.[31]

[24] Direct Rate Design Testimony of Staff Witness Solganick, page 14:4-6.
[25] Direct Rate Design Testimony of RUCO Witness Huber, page 36:10-11.
[26] Direct Rate Design Testimony of Staff Witness Solganick, page 11:15.
[27] Direct Rate Design Testimony of Staff Witness Solganick, page 10:4.
[28] Direct Rate Design Testimony of Staff Witness Solganick, page 10:11-12.
[29] Direct Rate Design Testimony of Staff Witness Solganick, page 10:18.
[30] Direct Rate Design Testimony of Staff Witness Solganick, page 10:21-22.
[31] Direct Rate Design Testimony of Staff Witness Solganick, page 11:1.

Q. Would you like to make any general comments regarding RUCO's rate design testimony?

A. Yes. The Company opposes RUCO's recommendations to (i) keep the third tier in the Company's two-part residential rates[32] and (ii) maintain the residential monthly basic service charge of $10[33], which is far below the Company's and Staff's proposals. It is critical that we address the Company's ability to recover its non-fuel revenues. As I stated in my Direct Testimony:

> Current rates for TEP's residential customers collect over 80% of the Company's fixed costs through volumetric charges based on electric consumption. TEP is proposing rate design changes that will provide more equitable cost recovery in an environment where overall electricity sales are declining yet the Company's cost of service requirements have increased.[34]

Please refer to the Rebuttal Testimonies of Company witnesses Dallas J. Dukes, Craig A. Jones and Carmine Tilghman for more information.

Q. Is the Company revising its net metering proposal?

A. No. TEP's Direct and Rebuttal Testimonies provide sufficient evidence that to find that it is in the public interest to (i) eliminate the banking of excess energy and (ii) provide monthly bill credits valued at the Renewable Credit Rate for excess energy produced from an eligible DG facility. The Company continues to support a grandfathering date of June 1, 2015.

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[32] Direct Rate Design Testimony of RUCO Witness Huber, 24:7-8.
[33] Direct Rate Design Testimony of RUCO Witness Huber, page 6:14.
[34] Direct Testimony of David Hutchens, page 12:12-16.

Q. Is there any recent research from credit rating agencies regarding rate design, net metering and the financial health of utilities?

A. Yes. On July 19, 2016, Fitch Ratings issued a report that highlights the challenges posed by the exponential growth in DG installations.[35] The report states, "The key to sustaining long-term IOU creditworthiness in the face of rapid distributed generation (DG) growth is modification of volumetric-based tariff design to incorporate a larger fixed charge component. Failure to address NEM rate design issues could lead to an unsustainable cycle of rising monthly bills for non-NEM customers, incentivizing them to acquire residential DG systems and leading to further rate increases and more departures."

Q. Is the Company still proposing to change to its LFCR?

A. Yes. As described in the Direct Testimony of Craig A. Jones, TEP is requesting that (i) the LFCR provide for the recovery of lost fixed-cost revenues associated with retail generation service and (ii) the cap on the LFCR be increased from 1% of total retail revenues to 2%.[36]

Q. Why are these changes necessary?

A. These proposed modifications are needed for the Company to fully recover approved non-fuel costs that would otherwise go unrecovered due to Commission mandated DG and EE programs. There is no reasonable basis for excluding generation costs from the LFCR as they constitute a large portion of the fixed costs incurred to meet retail customer demand. Although some parties have suggested that TEP can recoup these fixed costs by increasing sales in the wholesale market, that is simply not the case as explained further by TEP witness Kentton C. Grant. Should these fixed generation costs continue to go

[35] https://www.fitchratings.com/site/pr/1009126 .

[36] The Rebuttal Testimonies of Kentton C. Grant and Craig A. Jones discuss this topic in more detail.

unrecovered, the end result will be greater cost pressure on TEP and even larger rate requests down the road.

Q. Do you have any final remarks?

A. The Company's rate design proposals, including the requested changes to net metering and the LFCR, are critical and in the public interest. Maintaining the status quo (i) perpetuates the Company's well-documented problems of fixed cost recovery and the DG cost shift and (ii) affects the magnitude and frequency of future rate requests. Neither of these outcomes is in the public interest.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

Rebuttal Testimony of

Susan M. Gray

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-1933A-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

REBUTTAL TESTIMONY OF

SUSAN M. GRAY

ON BEHALF OF

TUCSON ELECTRIC POWER COMPANY

JULY 25, 2016

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Susan Gray. My business address is 88 East Broadway Blvd., Tucson, Arizona 85701.

Q. Did you file Direct Testimony in this docket?

A. Yes.

Q. What is the purpose of your Rebuttal Testimony?

A. The purpose of my Rebuttal Testimony is to describe TEP's distribution planning process and to respond to some of the statements made by RUCO witness Radigan and made by IBEW's witness Northrup.

II. DISTRIBUTION PLANNING PROCESS.

Q. Please describe how TEP's approach towards distribution planning and construction meets the needs of its customers in a cost-effective manner.

A. TEP's approach to distribution planning and construction is based on a 10-year forecast of peak demand, not total kWh sales. Customer growth leads to load growth and overall system growth. While customers may reduce their kWh usage, their peak demand may nonetheless grow. For example, if a customer installs roof-top solar on their home, their billed-energy usage will significantly decrease; however, when a cloud passes over on a hot, humid day, TEP must be able to instantly meet their full demand. This peak demand growth drives distribution planning and construction for TEP.

TEP is required to build a system able to meet the maximum peak demand for EVERY customer, EVERY hour of the day. This is accomplished through analysis of every one of

the Company's 410 circuits in the system, not by simply analyzing an aggregated sales forecast. Since 2011 (test year from last case), TEP has added about 10,000 new customers. So while overall sales volumes have declined, our system must account for the load requirements of these new customers. Load grows in pockets, not in an even distribution across the system. As such, TEP models each circuit with the current and anticipated load to evaluate the long-term needs in the area. As TEP becomes aware of plans for future growth, we incorporate those plans into the capital planning process.

Q. Please describe in more detail the length of the planning phase.

A. Building new substations and transmission lines is a lengthy process that includes often protracted land purchases, a siting process and an environmental permitting process. TEP begins the land acquisition and siting process at least five years in advance of planned construction. The lengthy timeline to build infrastructure to accommodate load growth doesn't allow for minor, short-term adjustments to customer building plans. Transmission and distribution assets have 30-50 year asset lives, so our plans can't be short-sighted, as Mr. Radigan suggests. If we install transformers sized for only the first 10 years of growth, we'll be replacing or adding transformers in a very costly and inefficient manner. We do incorporate potential growth as well as known growth in our forecasts, but known growth timelines can change and the external forces on our process aren't flexible enough to adjust accordingly. However, we do adjust our planning process for significant new/previously unknown changes in customer load.

Q. Please describe how this planning process is cost-effective.

A. TEP's approach to distribution planning incorporates the long-term needs of the system, which results in adding capacity to address current system needs while planning for future needs. This is a cost effective approach, because the Company can optimize the size of equipment to prevent the need for near-term replacements or additions. It is less expensive

to size equipment with room for growth, than to size for the immediate need and constantly have to replace or add equipment as growth occurs. Moreover, the Company can take advantage of economies of scale through longer-term planning. For example, a 138/13.8 kV 15 MVA transformer costs $600,000 compared to $675,000 for a 25 MVA transformer. Similarly, a 30 MVA transformer costs $1.0 million, compared to $1.2 million for a 50 MVA transformer.

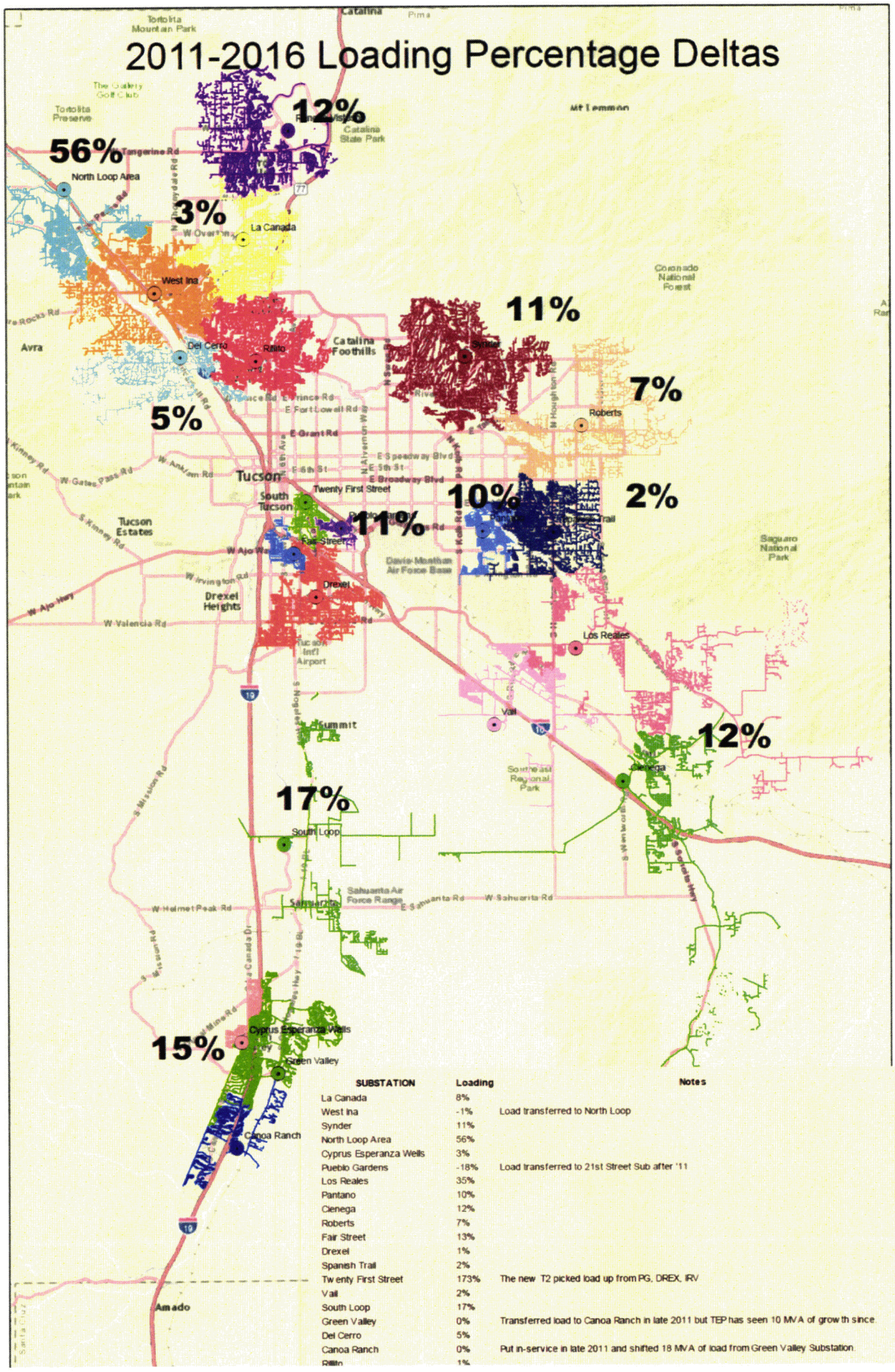
Q. If load growth forecasts change significantly, how does the Company adjust its planned system investments?

A. There are steps in the planning process where we can delay to adjust to changes in customer load. For example, once we purchase and permit a new substation site, we can postpone physical construction until the load growth is more certain. Land purchase plans can also shift, adjusting in-service dates to reflect to changes in the forecast. For example, the original in-service date for Orange Grove substation was 2013 in 2008, 2014 in 2009 and 2010, 2016 in 2011, 2017 in 2012, 2019 in 2013 and is currently forecast for 2018, which has been the planned in-service date since 2014.

Q. Please describe in more detail how growth in the number of customers affects the distribution system.

A. TEP builds new facilities to accommodate new customers (load growth), but also in response to gradual increases in demand that occur sporadically throughout TEP's service territory. Despite a reduction in total electricity consumption since the last rate case, we've seen load growth in certain pockets of our service territory which has reduced available capacity on existing infrastructure. The map below indicates the change in loads from 2011 to 2016, which greatly varies across the service territory.

2011-2016 Loading Percentage Deltas



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Synder	11%	
North Loop Area	56%	
Cyprus Esperanza Wells	3%	
Pueblo Gardens	-18%	Load transferred to 21st Street Sub after '11
Los Reales	35%	
Pantano	10%	
Cienega	12%	
Roberts	7%	
Fair Street	13%	
Drexel	1%	
Spanish Trail	2%	
Twenty First Street	173%	The new T2 picked load up from PG, DREX, IRV
Vail	2%	
South Loop	17%	
Green Valley	0%	Transferred load to Canoa Ranch in late 2011 but TEP has seen 10 MVA of growth since.
Del Cerro	5%	
Canoa Ranch	0%	Put in-service in late 2011 and shifted 18 MVA of load from Green Valley Substation.
Rillito	1%	

Q. How does TEP plan for contingencies?

A. In order to plan for contingencies, TEP must evaluate the loading of individual components of the system and have excess capacity on surrounding equipment to absorb the load in the event of a failure. In substations, we use Automatic Throw-over Switches (ATOs) to shift load from one transformer to another when a breaker operates (an automatic closing of a normally open switch between two connected transformers). This alleviates outages associated with the breaker operation, but requires excess capacity on the adjacent equipment to carry the additional load. Without the ATO in service, in the event of a failure, TEP personnel must devise a switching plan to re-balance the load and manually switch to re-energize the affected customers. This can result in an outage lasting several hours, versus no outage at all when an ATO is in service. Our planning process identifies and addresses areas where ATO's must be taken out of service during seasonal peaks by increasing capacity in existing or new substations.

Q. Please comment on TEP's future distribution system requirements.

A. TEP's plan for the future is to migrate substations from 46kV to 138kV, where it is most cost effective, for improved reliability and system efficiency. The 46kV system is radial, while the 138kV system is looped. As such, an outage on a 46kV line leads to 4,000-6,000 customers out of power until the line can be manually switched to pick up the load. An outage on the 138kV system does not result in customer outages because the loop is immediately fed from the other direction. In addition to improved reliability, as the Company replaces 46kV substations with 138kV substations, it will eliminate older equipment that has higher operating and maintenance costs.

III. RESPONSE TO RUCO.

Q. In your opinion, does Mr. Radigan understand the basic requirements involved in distribution system planning necessary to provide reliable electric service?

A. No. His testimony relies on declining kWh sales to assess the Company's distribution planning process. As I previously mentioned, we're building and maintaining the system to reliably and safely meet the specific load requirements of our customers, which includes meeting their peak demand.

Q. Please respond to some of Mr. Radigan's specific examples.

A. Certainly. I will briefly rebut each of the examples used in Mr. Radigan's testimony where he questions the Company's distribution system investments.

Canoa Ranch

While Mr. Radigan agrees that the Canoa Ranch substation relieved loading issues on existing substations, he suggests that the 50 MVA transformer was oversized because it currently has excess capacity. As explained earlier in my testimony, we are not planning for the short term, but rather for the 30-50 year life of a substation transformer. If TEP followed Mr. Radigan's planning approach, the Company would already be at full capacity only 5 years after the substation was built. That's just poor planning and a short-sighted and inefficient approach to investing in our distribution system which would lead to costly additions and compromised reliability.

Since the Canoa Ranch substation was built in 2011, we have experienced an additional 10 MVA of load growth on the Green Valley substation. The Canoa Ranch substation was built to alleviate loading and voltage issues at the southern end of Green Valley. However, rapid development in the northern portion of Green Valley has created new loading issues

in the area. In fact, the Company is currently replacing a transformer at the Hartt substation (located north of the Green Valley substation) to move some of the load from Green Valley to Hartt.

As previously discussed, TEP's long term strategy is to build 138kV substations like Canoa Ranch. With the addition of the new substation, an older 46kV substation was retired, reducing O&M costs associated with the older equipment. Moving the load to Canoa Ranch moved approximately 2,000 customers to the looped 138kV system and has resulted in improved reliability for those customers.

In summary, the Canoa Ranch system is appropriate based on long term planning. It resolved voltage issues on this system, as well as helping with load issues on nearby systems. It also provides the benefits of a looped system. This project is well justified, in the public interest, and TEP fully stands by its decision.

Lateral 7.5

Mr. Radigan questions the decision to install a 25 MVA transformer and suggests that a 15 MVA would have been adequate. Again, this is a short-sighted approach to planning. If TEP installed a 15 MVA transformer, it would already be 87% loaded (13 MVA), less than nine years after it was installed. Our forecasted load growth for this area reaches almost 27 MVA by 2023. Again, TEP's actions are consistent with sound long term planning. While Mr. Radigan's approach would have saved a little money in the short term, it would be far more costly in the long term.

Kino

Mr. Radigan states that the "Kino area in southern Tucson is serviced by five substations, 21st St, 35th St, Pueblo Gardens, Drexel, and Fair St." While TEP has been able to serve the load growth at The Bridges with these substations thus far, the ultimate build out of the development is over 45 MVA and cannot be served without the new 75 MVA Kino substation. Multiple circuits at the Drexel and Irvington substations are 90-100% loaded and we are not able to keep the ATO's in service during the summer peak. Building the Kino substation will alleviate these loading issues. TEP will also retire Pueblo Gardens and 35th Street, both 46kV substations have older equipment and higher maintenance costs. Moving the 35th Street and Pueblo Gardens load to a 138kV substation like Kino will greatly improve the reliability for the 3,000 customers served by those substations.

Q. With reference to a residential and commercial development called "the Bridges," Mr. Radigan states, "...there has been little meaningful development at the Bridges in the last 10 years."[1] Is this a true statement?

A. No. The Bridges is a growing commercial development. There has been an influx of new business in this area, including a Costco, Wal-Mart and several other smaller businesses,

[1] Direct Revenue Testimony of Frank Radigan, page 27:2-3.

which were not shown in Mr. Radigan's misleading photos. In addition, there are plans for a movie theater (currently under construction), restaurants, and the construction of 160 residential homes. In addition, the Company is aware of plans to break ground in 2018 on a large development with significant load requirements. The total development plan for The Bridges area is 45-50 MVA, with over 4 MVA already in service.

Q. Mr. Radigan states that TEP should, "wait as existing equipment becomes unloaded due to declining sales"[2] to increase system reliability. Do you agree with this statement?

A. Absolutely not. Mr. Radigan's approach to increasing system reliability is completely unrealistic and shortsighted. We make decisions that are in the best long-term interests of our customers. As I explained earlier, TEP's distribution planning process is very thorough. In my 19 years with TEP, we have never relied on declining kWh sales to enhance system reliability. In fact, I can't imagine that any utility in the United States would employ this type of planning approach. I cannot stress enough that system load and kWh sales are two very different things. The distribution system must be capable of meeting the peak load of our entire system.

Declining sales are not reflective of system need. For example, even though TEP is seeing declining kWh sales, TEP experienced a city peak load on June 20, 2016 of 2,305 MW, which was an increase of 4% over the 2015 peak of 2,214 MW. This demonstrates that declining sales doesn't necessarily create capacity.

[2] Direct Revenue Testimony of Frank Radigan, page 23:1-2.

Q. Are you aware of a provision in the 2013 settlement agreement approved in TEP's last rate case[3] that requires the Company to meet with RUCO (and Commission Staff) annually to discuss capital expenditures, specifically for the distribution system?

A. Yes, I am. In the 2013 settlement agreement TEP agreed to meet annually with RUCO and Staff to discuss the Company's capital expenditures for distribution plant, planning horizons and related planning for the upcoming year.

Q. Is TEP holding these meetings with RUCO and Staff?

A. Yes. TEP met with RUCO and Staff on December 1, 2014 and December 2, 2015 to discuss plans for distribution system investments as required by the settlement agreement, and we also discussed TEP's plans for investments across our entire utility system, including generation and transmission assets. Copies of the presentation materials from those meetings are attached as exhibits to the Rebuttal Testimony of David G. Hutchens.

Q. What do you believe is the intent of these meetings?

A. The Company's goal in these meetings is to (i) keep RUCO and Staff apprised of TEP's capital investment plans, (ii) discuss any significant initiatives or projects, and (iii) solicit questions and feedback from RUCO and Staff regarding the Company's plans.

Q. Do you think these meetings have been helpful for RUCO and Staff?

A. While I cannot speak for RUCO, Staff witness McGarry specifically mentions these meetings in his Direct Testimony as follows:

> TEP agreed to meet annually with Staff to review the Company's actual capital spending and future plans for the upcoming year.

[3] Decision No. 73912 (June 27, 2013).

Meetings with Staff were held in December 2014 and then again in December 2015. Information presentation in these meetings is consistent with what the Company has overall included for recovery in current rate base. I would recommend that these meetings continue as Staff has conveyed that they were useful in gaining a clearer picture of what the Company was planning for the upcoming years.[4]

Q. Does TEP support Staff's recommendation that these meetings continue?

A. Absolutely. TEP appreciates the opportunity to meet with RUCO and Staff to discuss our capital expenditure needs and to discuss any major initiatives in our planning horizon.

IV. RESPONSE TO IBEW.

Q. Do you agree with Mr. Northrup's multiple assertions of "marked deterioration in the reliability and safety of TEP's operations"?

A. No, I absolutely disagree. TEP has maintained an exemplary safety and reliability record for the past several years.

I will begin with safety. As stated on page 4 of my Direct Testimony, T&D Operations has maintained an excellent and sustained total recordable incident rate ("TRIR"). The T&D TRIR has hovered around 1.0 from 2012 through June of 2016, as demonstrated in the table below. The following formula was established by the Occupational Safety and Health Administration to calculate TRIR:

[4] Direct Revenue Testimony of Michael McGarry, page 29:9-15.

TRIR = (# of Recordable Injuries * 200,000) / # hours worked

	2012	2013	2014	2015	YTD June 30, 2016
T&D Operations TRIR	0.80	0.96	1.67	0.40	1.59

Simply stated, a TRIR of 1.0 reflects on average one OSHA recordable incident per 100 workers per year. This excellent safety performance is a reflection of our commitment to safety and our overall "Target Zero" safety strategy, which includes three elements:

1. Active safety leadership;
2. Increased employee involvement and engagement in safety activities; and
3. Hazard control and regulatory compliance.

Q. Please comment on TEP's reliability performance.

A. TEP has maintained consistent focus on reliability. On page 5 of my Direct Testimony, I also demonstrate the Company's consistent reliability performance. The following table illustrates sustained performance for CAIDI and improved performance in SAIDI and SAIFI.

	2011 – 2013 3-year average	**2013 – 2015 3-year average**
	Value (minutes)	**Value (minutes)**
SAIDI	75.73	63.09
SAIFI	.91	.75
CAIDI	83.68	84.23

Thus, TEP's electric customers on average experience less than one outage per year with an average duration of about one hour. For those customers experiencing an outage the average duration is less than 90 minutes.

Q. Do you agree with Mr. Northrup's concerns about Line Construction resources?

A. No, and I believe Mr. Northrup contradicts himself in his testimony on this matter. On the one hand, he asserts that we don't have as many linemen per customer as Central Hudson (page 6, lines 1-13), yet he later states that crews don't have enough work to stay busy (page 7, lines 10-11).

Many factors impact the timing of line construction work including: customer deadlines, regulatory requirements, outage coordination and permits. We often experience peaks and valleys in the volume of work due to these factors. The Company uses contractor resources to manage the fluctuations in work volume, which reduces the risk of laying off TEP employees when the workload is lighter. Comparing staffing between TEP and Central Hudson isn't valid because Central Hudson has very different business drivers including weather, vegetation, multiple district offices and availability of contractors in emergency situations.

We occasionally have large projects, like the 500kV line from Pinal Central to Tortolita or the 100 pole relocation public improvement project on Ajo Highway, that require many line construction resources for a short period of time. If we increased TEP resources to the level required to build these large projects, we would have to lay off those employees when the project was complete, which would be costly and inefficient.

Q. Is it true that TEP is not currently maintaining records for non-CIP (Critical Infrastructure Protection) breakers?

A. No, that is not true. We maintain records for all 1,349 of our substation breakers, whether they are designated as CIP or not. These records include the name plate information, test data, inspections, and history of maintenance that has been performed on the breakers since the installation date.

Q. Are you aware of "a disruption in the Company's workflow inasmuch as some crews do not actually have sufficient work to stay busy" as Mr. Northrup states on page 4, lines 9-11?

No, I am not aware of crews not having sufficient work to stay busy. The Company's Resource Management Team and Line Construction leadership coordinate closely to ensure that crews are assigned productive work every day. As demonstrated in the table below, TEP line crews have maintained a consistent level of work for the past 3 years. The minor differences are due to fluctuations in emergency work, including storm response.

	2013	2014	2015
Hours worked by TEP Line Crews	224,090	222,392	219,313

Q. Is Mr. Northrup's testimony describing Designers and Designer Apprentices as not qualified accurate?

A. I assume that Mr. Northrup is referring to the Distribution Designers in the T&D Operations department because this is the only current designer position. Based on that assumption, my answer is no, Mr. Northrup's testimony is not accurate. Mr. Northrup infers that the recently hired Distribution Design contractors are not qualified, which is not correct. Both of the contractors have over 10 years of experience as Distribution Designers

at other utilities and are qualified to perform this function at TEP. These contractors were identified through a nation-wide search and pre-qualification by a national recruitment firm. Multiple candidates were interviewed and TEP contracted with the top two candidates. In conjunction with hiring two Distribution Designer contractors, the Company is currently in the process of hiring a new class of at least four Distribution Designer Apprentices, which will be TEP's largest class ever of this type of apprentices.

Q. Do you understand the connection that Mr. Northrup is making between the Distribution Designers in T&D Operations and page 17 of your testimony?

A. No. Page 17 of my testimony is about the workforce planning efforts for T&D Engineering, not Operations. The designers mentioned in this section of my testimony are Engineering Designers, which is a position that does not yet exist at TEP.

Q. Does TEP hire out of state contractors?

A. Yes. TEP hires both in state and out of state contractors in order to ensure costs are reasonable. All construction contractors hired by TEP are required to hold licenses in the state of Arizona.

Q. Mr. Northrup's testimony states "TEP also just bid two transmission jobs out that could have been performed by TEP employees." Is this accurate?

A. No. TEP had an unusually high volume of transmission work in 2015 and 2016. While our employees are capable of doing this type of work, the employee and equipment resources required to complete all of the concurrent line work in 2015 and 2016 exceeded our internal capabilities. The Company takes into account many factors when determining to use internal or external resources for construction, including: length of the project, equipment requirements, other projects due at the same time, outage requirements,

proximity to the Irvington office and due dates. Work is assigned to internal and external crews in a manner to optimize efficiency and productivity.

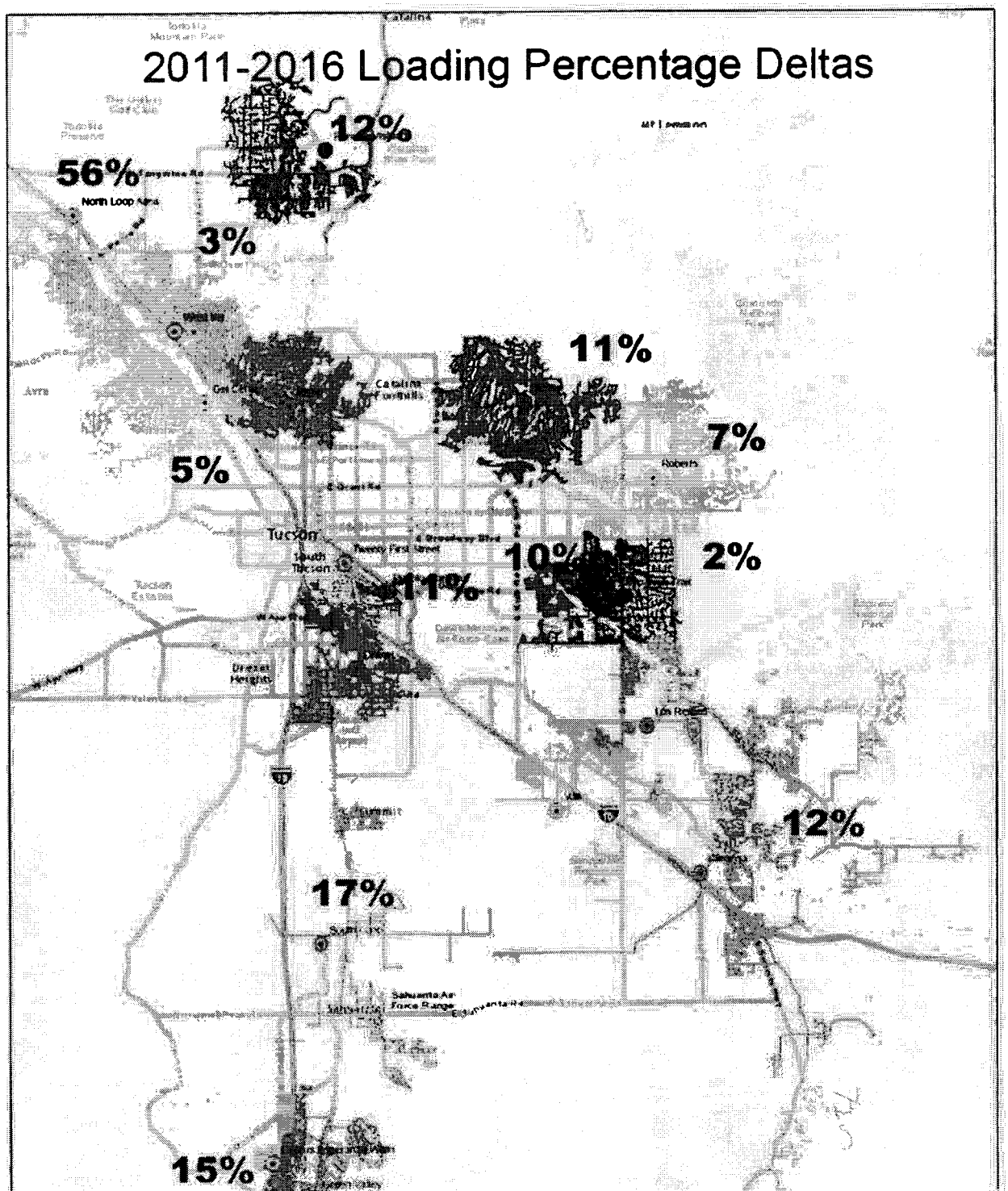
Q. Please comment on Mr. Northrup's statement expressing concerns related to TEP's workforce planning initiatives and the 'aging workforce' problem.

A. We actively monitor and manage our Workforce Planning initiatives as they relate to not only retirements, but the changing business environment in which we are operating. Workforce planning is addressed on an on-going basis within the functional areas of the company and formally on an annual basis through efforts specific to organizational planning. Additionally, these workforce plans are incorporated and discussed during the annual business planning cycle and subsequent succession reviews.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

2011-2016 Loading Percentage Deltas



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Rebuttal Testimony of

Kentton C. Grant

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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-1933A-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

Rebuttal Testimony of

Kentton C. Grant

on Behalf of

Tucson Electric Power Company

July 25, 2016

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Kentton C. Grant and my business address is 88 East Broadway, Tucson, Arizona, 85702.

Q. Did you file Direct Testimony in this proceeding?

A. Yes.

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. My Rebuttal Testimony is filed on behalf of Tucson Electric Power Company ("TEP" or the "Company").

Q. Which Commission Staff and/or Intervenor Testimony do you address in your Rebuttal Testimony?

A. My Rebuttal Testimony addresses the testimony filed on behalf of the Commission Staff ("Staff"), the Department of Defense ("DOD"), Arizonans for Electric Choice and Competition ("AECC"), the Residential Utility Consumers Office ("RUCO") and Local Union 1116 of the International Brotherhood of Electric Workers ("IBEW") in the following subject areas:

- Cost of Capital and Fair Value Rate of Return ("FVROR")
    - Staff Witness David C. Parcell
    - DOD Witness Michael P. Gorman
    - RUCO Witness Robert B. Mease
- O&M Cost Recovery on a 50.5% Share of Springerville Unit 1
    - Staff Witnesses Michael J. McGarry, Sr. and Donna H. Mullinax
    - AECC Witness Kevin C. Higgins

- Rate Base Treatment of Springerville Unit 1
    - AECC Witness Kevin C. Higgins
- Rate Base Treatment of TEP Headquarters Building
    - AECC Witness Kevin C. Higgins
    - RUCO Witness Frank W. Radigan
- Financial Condition of TEP
    - IBEW Witness Scott Northrup

Additionally, I discuss the potential impact of the recommendations made by Staff and certain Intervenors on TEP's financial health.

II. FINANCIAL IMPACT OF PARTIES' RECOMMENDATIONS.

Q. What is the potential impact of the recommendations made by Staff and the Intervenors on TEP's financial health?

A. Collectively, the revenue requirement adjustments recommended by the various parties to this proceeding would deal a serious financial blow to TEP. The Direct Testimony filed by the various parties include a wide range of disallowances of TEP's operating costs and plant investments, unreasonably low returns on the Company's invested capital, and jurisdictional cost allocations that severely understate the cost of generation used to provide retail electric service.

When looked at individually, the positions of Staff and certain Intervenors range from being unsupportive of TEP's current credit ratings to being extremely negative. On one end of the spectrum is Staff, which has recommended that TEP's requested rate relief be cut by more than half, and has also rejected the Company's request to recover approximately $16 million of Springerville Generating Station Unit 1 ("SGS Unit 1")

operating costs through the Company's purchased power and fuel adjustment clause ("PPFAC"). On the other end of the spectrum is RUCO, which has recommended that TEP's rate request be slashed by more than 80%, and has made other recommendations (along with AECC, Western Resource Associates and the Sierra Club) that would lead to large write-offs of TEP's utility plant and common equity balance. In short, the recommendations of Staff and certain Intervenors, if adopted, would not provide the Company with an opportunity to earn a reasonable rate of return on invested capital, and would likely lead to a downgrade of one or more notches to TEP's credit ratings. Such an outcome would be inconsistent with prior Commission orders, such as the 2014 Fortis Merger Order (Decision No. 74689 (August 12, 2014)) and the 2016 TEP Financing Order (Decision No. 75414 (January 19, 2016)), both of which encourage the Company to either maintain or improve its financial integrity.

Q. Are you saying that TEP needs 100% of its requested rate relief in order to avoid a credit rating downgrade?

A. No. However, cuts in the magnitude recommended by Staff and certain Intervenors would have an obvious adverse impact on the Company's earnings and cash flow, two financial measures that are heavily weighted in the credit rating review process.

Q. Has TEP revised its non-fuel rate request in response to the testimony filed by Staff and the Intervenors?

A. Yes. The Company is reducing its requested return on equity ("ROE") from 10.35% to 10.00% and is making other adjustments to its revenue requirement and the jurisdictional allocation of generation costs. These adjustments result in a $24 million reduction to the Company's non-fuel rate request. As I discuss later in my testimony, the Company is also revising its request to recover approximately $16 million of SGS Unit 1 operating costs through the PPFAC. Based on the anticipated ownership of 100% of SGS Unit 1

before the effective date of a rate order in this proceeding, and the opposition of Staff and AECC to the use of the PPFAC for this purpose, TEP is now requesting recovery of approximately $15 million of those costs through non-fuel rates. Although the impact on total revenues is expected to be neutral, this shift from PPFAC recovery to non-fuel rate recovery results in a revised non-fuel revenue deficiency of $100.6 million, compared with TEP's original request of $109.5 million.

Q. Are the parties' positions with respect to rate design and cost recovery mechanisms also important to the Company's credit profile?

A. Yes. Due to the rapid deployment of rooftop solar generation in TEP's service territory, as well as increased energy efficiency and customer conservation, it is becoming increasingly important from a credit rating perspective that a larger share of non-fuel fixed costs be recovered through monthly customer charges and/or customer demand charges as opposed to volumetric rates (per kWh consumed). As an example, Staff's recommendation to increase monthly customer charges and to eliminate the third and fourth rate tiers for residential customers would significantly improve fixed cost recovery from those customers.

It is also important, from both a public policy perspective and a credit rating perspective, to address the ongoing cost shift resulting from the Commission's net metering policies, as well as the lack of generation fixed cost recovery through the Lost Fixed Cost Revenues ("LFCR") adjustor mechanism. So long as substantial cost subsidies are provided to net metering customers, TEP's remaining customers without self-generation will be asked to bear an increasing share of the Company's infrastructure costs in each future rate proceeding. And until the conclusion of those future rate proceedings, absent any change to the Company's LFCR, any lost fixed-cost revenues associated with TEP's generation portfolio will simply go unrecovered, thereby contributing to the frequency

and magnitude of future rate requests. Unfortunately, neither Staff nor any of the Intervenors expressed support for the recovery of lost generation fixed-cost revenues through the LFCR, and only one party, RUCO, proposed any meaningful reform to the Company's net metering tariff.

Q. Why is it important that the LFCR be amended to allow recovery of lost fixed-cost revenues associated with TEP's generation portfolio?

A. TEP has a substantial investment in generation plant that is used to provide retail electric service. Like other utility plant assets, generation plant has a long useful life and has fixed costs attached to it such as depreciation expense, O&M expense and property taxes. Currently, when TEP loses retail sales due to increased rooftop solar deployment and the implementation of energy efficiency programs, the fixed costs and return requirement associated with the Company's retail generation investment simply go unrecovered. Although some parties have argued that TEP can make up any retail losses in the wholesale market, that is simply not the case. Since all revenues from short-term wholesale sales get credited to the Company's PPFAC balance, the only recourse left to TEP would be to sign up new long-term wholesale customers.

There are at least three problems with such a strategy. First, the wholesale power market is currently very depressed. As a result, new long-term contracts are difficult to come by and typically have pricing that is well below TEP's fully embedded cost of generation. Second, long-term wholesale commitments serve to reduce the amount of TEP generation available to meet future retail customer needs, and therefore impact the Company's integrated resource plans and future cost of power supply. Finally, as demonstrated by testimony filed on behalf of RUCO and AECC in this rate case, there are some parties who believe that TEP's long-term wholesale sales should subsidize the cost of providing retail electric service, either through some form of "profit sharing" or through an

oversized allocation of costs to the wholesale jurisdiction. For these reasons, as well as others, the Company's LFCR should be modified to provide for recovery of lost fixed-cost revenues associated with retail generation service.

III. COST OF CAPITAL AND FVROR.

A. Weighted Average Cost of Capital.

Q. What is TEP's weighted average cost of capital ("WACC") now that the Company has reduced its requested ROE from 10.35% to 10.00%?

A. This concession reduces the Company's WACC from 7.34% to 7.16%. The revised WACC is shown in the following table:

	% of Capital Structure	Component Cost	Weighted Average Cost
Common Equity	50.03%	10.00%	5.00%
Long-Term Debt	49.97%	4.32%	2.16%
Total	100.00%		7.16%

Q. Did the Company make any changes to its proposed capital structure or cost of debt?

A. No.

B. Capital Structure.

Q. Did any witnesses recommend using a different capital structure than the one proposed by TEP?

A. Yes. Staff witness David C. Parcell and DOD witness Michael P. Gorman each recommend using a capital structure consisting of 48.69% common equity and 51.31% long-term debt. This capital structure contains less equity and more long-term debt relative to the capital structure proposed by TEP. As discussed on pages 11-12 in my Direct Testimony, the capital structure proposed by TEP contains 50.03% common equity and 49.97% long-term debt.

Q. What is the source of this difference?

A. TEP's proposed capital structure removes two series of bonds that were retired shortly after the test year, whereas Mr. Parcell and Mr. Gorman used a test-year capital structure that includes both series of bonds.

Q. Why is it appropriate to remove the two series of retired bonds from the test year capital structure?

A. As explained in my Direct Testimony, a portion of the $180 million equity infusion made by Fortis and UNS Energy in 2015 was set aside for the retirement of two series of bonds with a combined principal amount of $78.6 million. Irrevocable redemption notices had already been sent to the bondholders before the end of the test year, and cash necessary to make the redemptions was held by TEP at test-year end. Since the bonds were retired in August 2015, well before the Company's rate filing, and long before the hearing in this case, it is appropriate to remove them for purposes of determining the capital structure and the WACC.

Q. What reasons were offered by Mr. Parcell and Mr. Gorman in support of their recommendations?

A. On page 19 of his Direct Testimony, Mr. Parcell states that "Staff's long-standing policy is to rely upon actual test year figures and to not generally incorporate out-of-period adjustments." Mr. Gorman offers a different rationale, namely that "adjusting TEP's actual capital structure will inflate its claimed revenue deficiency in this proceeding, without justification." (See Gorman Direct, p. 14.)

Q. Do you agree with these explanations?

A. No. I disagree with Mr. Parcell because the Commission has recognized pro-forma adjustments to reflect known and measurable changes to test year figures. Here, the redemptions occurred many months ago and are certainly "known and measurable." Further, the cost of capital is a forward-looking concept, and these bonds which were retired almost a year ago will not be part of TEP's capital structure going forward. The fact that TEP irrevocably committed to these redemptions before the end of the test year only makes the case for recognizing this change stronger. As for Mr. Gorman's contention that TEP's capital structure is "inflated" and "without justification," I strongly disagree.

Q. Please explain your disagreement with Mr. Gorman.

A. As described on 12-13 of my Direct Testimony, the Company's proposed capital structure is in line with other investor-owned utilities with investment-grade credit ratings, and has a lower proportion of common equity than was allowed for UNS Electric, Inc. and Arizona Public Service Company in their most recent rate orders. Additionally, the Settlement Agreement approved in the Fortis merger docket contains a dividend restriction applicable to TEP for a period of five years, or until such time as the Company's equity capitalization reaches 50% of total capital. That provision would not

have been included in the Settlement Agreement, and approved by the Commission, unless a 50% equity ratio was deemed to be reasonable by the Staff and the Commission. It therefore appears that Mr. Gorman is substituting his own judgment for that of the Commission when he refers to a capital structure with 50.03% common equity as being "without justification."

Q. Has TEP maintained a capital structure after the test year consistent with the proposed capital structure?

A. Yes. As of year-end 2015, as well as quarter-end March 2016, TEP had a capital structure consisting of 50.5% common equity and 49.5% long-term debt. These values were calculated in the same manner as reflected in Schedule D-1 in the Company's rate application, and are also provided in **Exhibit KCG-R-1** attached to my Rebuttal Testimony.

C. <u>Cost of Debt.</u>

Q. Did any witness recommend using a cost of debt different from that proposed by TEP?

A. Yes. Staff witness David Parcell recommends a cost of debt of 4.14%, whereas TEP is proposing a cost of debt of 4.32%. The difference relates to the two series of bonds that were retired in August 2015.

Q. Has TEP maintained a cost of debt after the test year consistent with the proposed cost of debt?

A. Yes. As may be seen in **Exhibit KCG-R-2**, TEP's weighted average cost of debt was 4.30% as of December 31, 2015 and March 31, 2016. These values were calculated in the same manner as shown in Schedule D-2 in the Company's rate application.

Q. Does TEP still propose using a 4.32% cost of debt as reflected in its rate filing?

A. Yes. This value is very close to the current cost of debt for TEP, and is lower than the cost of debt TEP will likely experience in future years due to anticipated monetary tightening by the U.S. Federal Reserve and the impact that will have on the Company's variable-rate debt.

D. <u>Fair Value Rate of Return.</u>

Q. Has the Company's requested FVROR been revised to reflect the change in the requested ROE?

A. Yes. Additionally, the FVROR has been revised to reflect adjustments TEP has made to its requested rate base. As discussed in the Rebuttal Testimony of Company witness Ann Bulkley, the revised FVROR is now 5.57%, compared with an originally proposed FVROR of 5.69%.

Q. Did any witness propose a FVROR methodology different from that used by TEP?

A. Yes. RUCO witness Robert B. Mease applies a methodology that is different from that applied by both TEP witness Ann Bulkley and Staff witness David Parcell. Additionally, DOD witness Michael Gorman argues that little weight, if any, should be given to the fair value rate base ("FVRB") when determining the return requirement for TEP.

Q. What methodology does Mr. Mease use to calculate a FVROR for TEP?

A. As described on pages 34-35 of his Direct Testimony, he subtracts an inflation adjustment of 1.56% from his recommended cost of capital of 6.76% to arrive at a FVROR of 5.20%. He justifies this approach by referring to a "double-counting" of inflation that would otherwise occur without this adjustment.

Q. Do you agree with the methodology used by Mr. Mease to determine the FVROR?

A. No, I do not. It is a methodology that is not practically or theoretically sound.

Q. Please comment on the theoretical shortcomings of this methodology.

A. As noted by Mr. Mease, the difference between the Company's original cost rate base ("OCRB") and the FVRB is caused by inflation. That is because TEP relied on a traditional 50/50 weighting of the OCRB and the reconstructed cost new less depreciation ("RCND") rate base in calculating the FVRB. Inflation impacts only the RCND component of FVRB. Since the Company's FVRB is 50% weighted by the OCRB, which includes no inflation over original cost, Mr. Mease over-compensates for inflation by deducting a full rate of inflation from the WACC. Had he deducted only 50% of the rate of inflation from the WACC, his methodology would have been more theoretically sound.

Q. Are there other theoretical shortcomings associated with this methodology?

A. Yes. While the RCND rate base and 50% of the FVRB have been impacted by historical inflation, the Company's WACC is forward-looking, and is therefore impacted by future expectations for inflation. To complicate matters even further, the Company's embedded cost of debt reflects expectations for inflation as of each historical date of issuance, whereas the cost of equity is a forward-looking estimate that reflects current expectations for inflation. Consequently, there will always be a mismatch between the historical cost of inflation embedded in the RCND rate base and the forward-looking rates of inflation embedded in the cost of capital. There is simply no perfect way to eliminate the "double counting" of inflation that is embedded in both the RCND rate base and the WACC.

Q. What are some of the practical shortcomings of the FVROR methodology employed by Mr. Mease?

A. One practical shortcoming is the choice of an appropriate forward-looking inflation rate. Mr. Mease decided to average the forward-looking inflation rates observed over a seven-year period ending in 2015. (See Schedule RBM-4 attached to Mr. Mease's Direct Testimony.) His decision to use a seven-year average, as opposed to a more recent (and much lower) rate, is not discussed anywhere in his testimony. A second practical issue, and one that the Commission should be more concerned about, is that this methodology produces inherently unstable results as inflation expectations rise and fall over time.

Q. Please explain.

A. As an example, the inflation expectations calculated by Mr. Mease over the period 2009-2015 ranged from a low of 1.10% in 2015 to a high of 2.23% in 2011. (See Schedule RBM-4 attached to his testimony.) Even though this range of expected inflation is modest by historical standards, the resulting FVROR would be very different if either of those values had been selected in lieu of the 1.56% average rate used by Mr. Mease. The following table illustrates the impact of using these different inflation rates on the FVROR and revenue requirement for TEP, based on the Company's originally proposed WACC and FVRB:

	Low Rate from RBM-4	Avg. Rate from RBM-4	High Rate from RBM-4
WACC	7.34%	7.34%	7.34%
Inflation Adjustment	-1.10%	-1.56%	-2.23%
FVROR	**6.24%**	**5.78%**	**5.11%**
x FVRB ($000s)	$2,913,279	$2,913,279	$2,913,279
Return ($000s)	**$181,702**	**$168,301**	**$148,782**
x Gross-Up Factor	1.6223	1.6223	1.6223
Return & Taxes ($000s)	**$294,776**	**$273,035**	**$241,370**

As illustrated above, the impact of even minor changes in expected inflation can produce very different results in terms of the FVROR and overall revenue requirement. During periods of low inflation or deflation, the methodology used by Mr. Mease would produce a large return premium for most utilities. Conversely, during periods of high inflation, his proposed methodology would impose severe return penalties on most utilities, even if the FVRB exceeded the OCRB by a wide margin.

Q. Does the inflation adjustment proposed by Mr. Mease result in a FVROR penalty to TEP?

A. No, it does not. As illustrated in the table above, subtracting an inflation adjustment of 1.56% from the Company's originally requested 7.34% WACC would result in a FVROR of 5.78%. This value is higher than the FVROR of 5.69% originally proposed by TEP, as well as the 5.57% FVROR now being requested by TEP. However, for the reasons described above, the Company does not support the methodology used by Mr. Mease in calculating the FVROR.

Q. What FVROR does Mr. Mease recommend for TEP?

A. As mentioned earlier, he recommends a FVROR of 5.20%. The reason it is lower than the 5.69% value referenced above is that his WACC is based on a cost of equity of only 9.20%. Company witness Ann Bulkley addresses the cost of equity analysis of Mr. Mease in her Rebuttal Testimony, and also responds further to the FVROR methodology proposed by Mr. Mease.

Q. Please describe Mr. Gorman's position on FVROR.

A. On pages 69-72 of his Direct Testimony, Mr. Gorman argues that the Commission should set the FVROR at a level that produces the same return requirement as applying the Company's WACC to its OCRB.

Q. Do you agree with Mr. Gorman's position on FVROR?

A. No. He is recommending that the Commission use the now discredited "backing in" method for setting the FVROR. That method, which assigns no economic value to the FVRB, is premised on the following assumption:

Return Requirement = WACC x OCRB = FVROR x FVRB

Based on this assumption, the FVROR can then be calculated as follows:

FVROR = (WACC x OCRB) / FVRB

Although this method was formerly used in Arizona, it has now been rejected. The reason it was rejected is that the fair value of a utility's property must be taken into account when setting rates in Arizona. Under Mr. Gorman's preferred method, fair value is assigned zero weight in setting utility rates and therefore has no impact on the final result.

IV. O&M COST RECOVERY ON A 50.5% SHARE OF SGS UNIT 1.

Q. Did any of the parties address TEP's request to recover $16 million of O&M, property taxes and fuel handling costs on the co-owner share of SGS Unit 1 through the PPFAC?

A. Yes. Staff Witnesses Michael J. McGarry, Sr. and Donna H. Mullinax, as well as AECC witness Kevin Higgins, recommend that such costs not be allowed recovery through the PPFAC.

AECC witness Kevin Higgins objects to the request as a "special ratemaking proposal" that should not be allowed since TEP did not demonstrate "the reasonableness of its acquisition of the 50.5% co-ownership share of Springerville Unit 1." (See Higgins

Revenue Requirement Direct, page 14.) However, Mr. Higgins fails to explain how TEP could have demonstrated the reasonableness of the terms of an acquisition that had yet to be agreed upon at the time of the Company's rate filing. In assessing the reasonableness of the Company's request, he also fails to give any weight to the extraordinary nature of the litigation that TEP was facing, or the contingent nature of the Company's request for cost recovery.

Staff witness Michael McGarry recommends against recovery on policy grounds, since non-fuel costs are not typically recovered through the PPFAC. Additionally, he states that the timing of the request "is problematic since the transaction to acquire the 50.5% co-owner's share has not yet happened." (See McGarry Revenue Requirement Direct, page 13.)

Staff witness Mullinax refers to the testimony of Mr. McGarry, and also addresses the potential recovery of the $16 million of SGS Unit 1 operating costs through non-fuel rates. She states that Staff is not proposing an adjustment at this time since TEP has not provided any "comprehensive analysis" on the potential impact of the settlement and purchase of SGS Unit 1 on the Company's revenue requirement. (See Mullinax Revenue Requirement Direct, page 37.)

Q. Why did TEP request recovery of these non-fuel costs through the PPFAC?

A. In its original rate filing the Company sought PPFAC recovery of these costs due to the contingent nature of TEP's dispatch rights to this capacity, as well as the uncertain outcome of litigation that was pending at the time.

Q. Have there been any developments since TEP filed its rate application that would solidify the Company's rights to the co-owner share of share SGS Unit 1?

A. Yes. On February 29, 2016, TEP entered into an agreement with the SGS Unit 1 co-owners for the settlement and release of asserted legal claims and the purchase and sale of beneficial interests in SGS Unit 1. The agreement provides that TEP will purchase the co-owners' 50.5% undivided interest in SGS Unit 1 for $85 million (or $435 per kW of capacity), and the co-owners will pay TEP $12.5 million for operating costs related to SGS Unit 1 incurred by TEP on behalf of the co-owners. Upon completion of the purchase, all outstanding disputes and pending litigation and arbitration proceedings between TEP and the co-owners will be dismissed with prejudice. The purchase is subject to, among other things, Federal Energy Regulatory Commission ("FERC") approval and satisfaction of other customary closing conditions. TEP filed an application for approval with FERC on March 28, 2016, and the application is pending in FERC docket EC16-96-000. The Company expects to close the purchase in the third quarter of 2016, resulting in 100% ownership of SGS Unit 1 by TEP.

Q. Why did the Company pursue a settlement with the co-owners of SGS Unit 1?

A. There are several reasons. As mentioned in my Direct Testimony, the co-owners were in arrears to TEP for their share of O&M costs and capital expenditures. As the litigation between TEP and the co-owners progressed, it became apparent that it would likely take years to fully resolve all of the claims between the parties. Absent a settlement of the litigation, the Company faced the difficult decision of either mothballing the unit or continuing to operate the unit without any payments from the co-owners to cover O&M and capital expenditures on a 50.5% share of the unit. Additionally, over time the co-owners became more amenable to settlement, and ultimately they were willing to accept a substantial discount to the appraised value for their share of the unit. By entering into the settlement, the Company was able to resolve some very difficult legal, financial and

operating challenges, while at the same time securing a high quality generation resource at a reasonable price.

Q. Is the Company requesting rate base treatment of the $85 million purchase price in this rate proceeding?

A. No. Since TEP filed its rate application well before the settlement was reached, the $85 million purchase price was not included in the Company's requested revenue requirement. TEP expects that it will request rate base treatment of the proposed purchase, which reflects a substantial discount to the $478/kW appraised value of SGS Unit 1, in the Company's next rate case. However, consistent with the Company's original filing in this rate case, TEP is still requesting rate recovery of the non-fuel operating costs relating to this 50.5% share of SGS Unit 1.

Q. Is the Company now proposing to recover the $16 million of O&M, property taxes and fuel handling costs through non-fuel rates?

A. Yes. Since the Company now expects to own 100% of SGS Unit 1 before the effective date of a rate order in this proceeding, TEP has revised its non-fuel revenue requirement to include the $16 million of non-fuel operating costs associated with the 50.5% co-owner share of SGS Unit 1. However, since the Company has revised its jurisdictional allocation of non-fuel generation costs, the level of cost recovery has been lowered to approximately $15 million.

Q. Has the Company prepared any economic analysis in support of its decision to acquire the co-owner share of SGS Unit 1?

A. Yes. Company witness Michael Sheehan discusses the economic merits of the pending acquisition in his Rebuttal Testimony.

V. RATE BASE TREATMENT OF SGS UNIT 1.

Q. Did any parties file testimony recommending disallowances of SGS Unit 1 plant investment?

A. Yes. AECC witness Kevin Higgins recommends three separate disallowances:

- $23.9 million of leasehold improvements made by TEP during the term of the SGS Unit 1 leases;
- $16.3 million of the purchase price TEP paid for a 14.1% interest in SGS Unit 1 in 2006; and
- $0.9 million of acquisition costs TEP paid in connection with the end-of-lease purchases of a 35.4% interest in SGS Unit 1 completed in December 2014 and January 2015.

Q. Please describe the $23.9 million adjustment Mr. Higgins made to the requested SGS Unit 1 leasehold improvements.

A. In his Direct Testimony, Mr. Higgins recommends disallowing the remaining net book value of all leasehold improvements (i.e., capital expenditures on leased property) that TEP made during the term of the lease for a 50.5% share of SGS Unit 1. However, doing so would essentially penalize the Company for extending the amortization period of these improvements for the benefit of TEP's customers in the Company's last rate case.

The 50.5% share of SGS Unit 1 represented the portion of the unit that reverted back to the lessors at the end of the lease term in January 2015. As described on page 32 of my Direct Testimony, for accounting purposes, TEP reclassified the net book value of those leasehold improvements as a regulatory asset at the end of the lease. Mr. Higgins refers to the inclusion of the $23.9 million regulatory asset in rate base as a "special ratemaking proposal" that should be rejected because the Company has not demonstrated "the

reasonableness of its acquisition of the 50.5% co-ownership share of Springerville Unit 1." (See Higgins Revenue Requirement Direct, page 14.)

Q. Should the recovery of these leasehold improvements be dependent on the acquisition of a 50.5% share of SGS Unit 1 by TEP?

A. No. And at the time of TEP's rate filing, the Company was in no position to make any definitive case for acquiring this share of SGS Unit 1 due to ongoing litigation with the former lessors and co-owners of the unit.

Q. Why did TEP reclassify these leasehold improvements as a regulatory asset eligible for rate recovery?

A. The basis for reclassifying the leasehold improvements to a regulatory asset was that TEP had been allowed to include leasehold improvements in rate base in each of the last two rate cases. In the last rate case, the Company specifically requested that SGS Unit 1 leasehold improvements be amortized over a ten year amortization period, as opposed to the remaining life of the lease (which ended January 1, 2015) in order to moderate the rate impact on customers. Due to the longer amortization period, as well as additional leasehold improvements that were made during the final few years of the lease, a $23.9 million net balance of leasehold improvements remained at the end of the test-year for the 50.5% share of SGS Unit 1 not purchased by TEP. Since a large portion of this remaining balance represents plant investment that was found to be reasonable in TEP's last rate case, there is no reason it should now be deemed unreasonable and excluded from rate recovery.

Q. Are there other reasons why these leasehold improvements should be included in rate base and recovered over the amortization period established in the last rate case?

A. Yes. These improvements represent replacements and betterments of generation plant that were required for the continued operation of SGS Unit 1 and for continued compliance with various state and federal regulations. As may be seen on page 2 of Exhibit KCH-4 attached to Mr. Higgins' Direct Revenue Requirement Testimony, nearly two-thirds of the remaining net book value of leasehold improvements relate to prior capital spending on boiler plant equipment, with the remaining balance spent on structures, turbine and generator equipment, accessory electric equipment and other power plant equipment. That same equipment is being used today for powering the 49.5% share of SGS Unit 1 that TEP has owns and operates for the benefit of retail customers. And while it should not be determinative for ratemaking purposes, it should be noted that the Company now expects to own 100% of SGS Unit 1 following FERC approval of the proposed purchase of a 50.5% share from the co-owners and former lessors.

Q. Please describe the $16.3 million adjustment Mr. Higgins made to the cost of a 14.1% interest in SGS Unit 1 acquired in 2006.

A. Mr. Higgins recommends that the test-year net book value of the acquired asset be included in rate base, instead of the $42.7 million value recommended in my Direct Testimony. He derives the $16.3 million downward adjustment to rate base by subtracting a net book value of $26.5 million from the $42.7 million value requested by TEP. (See Higgins Revenue Requirement Direct, page 16.)

Q. Do you agree with Mr. Higgins' recommended adjustment?

A. No. There are three problems with this adjustment. First, his calculation of the net book value of $26.5 million is incorrect. Second, due to the nature of the acquisition made by TEP, and how it was accounted for on the Company's financial statements, there is no reasonable basis for using the net book value to determine rate base treatment. Third, Mr. Higgins fails to take into account how the 2006 acquisition was reflected in TEP's last two rate orders, and the resulting benefits that customers realized as a result of that rate treatment.

Q. How did Mr. Higgins derive a net book value of $26.5 million?

A. As shown on page 3 of Exhibit KCH-5 attached to Mr. Higgins' Direct Revenue Requirement Testimony, he applied a 14.1% allocation factor to a total net book value of $188.1 million for SGS Unit 1. However, that total net book value reflects a number of different purchase transactions by TEP, as well as other capital expenditures and leasehold improvements that were made to the unit. As such, the value calculated by Mr. Higgins does not reflect the net book value of the 2006 purchase transaction.

Q. What was the actual net book value at the end of the test year?

A. As shown in Confidential Exhibit KCH-19 attached to Mr. Higgins' Direct Revenue Requirement Testimony, the net book value of TEP's 14.1% interest in SGS Unit 1 was $36 million as of the end of the test year. (See column titled "2006 Lease Purchase" on page 7 of 9.)

Q. How did TEP account for its 2006 acquisition of a 14.1% lease equity interest in SGS Unit 1?

A. Since the Company purchased a lease equity interest in 2006, as opposed to an undivided interest in physical assets, TEP accounted for the purchase as an investment in lease

equity. Only when the lease expired in 2015, and TEP took direct title to the 14.1% undivided interest in SGS Unit 1, did the Company begin applying traditional plant accounting to this investment.

Q. Why is the Company requesting rate base treatment of $42.7 million out of the original $48 million lease equity purchase price?

A. As discussed on page 37 of my Direct Testimony, most of the cash flow benefit from purchasing the lease equity interest was passed onto customers through reduced SGS Unit 1 lease payments in the 2008 and 2013 rate orders for TEP. Only a small portion of the lease equity rent reduction, $5.3 million, was retained by TEP prior to the 2008 rate order. Hence, the Company is requesting the remaining dollar amount of its 2006 investment, $42.7 million, be included in rate base as the cost of acquiring a 14.1% undivided interest in SGS Unit 1.

Q. Please describe Mr. Higgins' recommended disallowance of $919,042 in legal costs for TEP's end-of-lease purchases of SGS Unit 1.

A. Mr. Higgins refers to these costs as "legal costs associated with its Alterna litigation." He goes on to state that "...the cost of litigating the disputes between TEP and Alterna should not be shouldered by customers, as the disputes between these two facility owners are outside the purview of providing retail service." (See Higgins Revenue Requirement Direct, pages 18-19.)

Q. Do you agree with Mr. Higgins' assessment?

A. No, I do not. Although all of the $919,042 of acquisition costs cited by Mr. Higgins are indeed legal costs, and also represent costs that could arguably be allocated to the 50.5% share of SGS Unit 1 held by Alterna Capital Partners and one other co-owner, they were not incurred to litigate the various disputes between TEP and Alterna that arose after the

lease expiration in January 2015. Instead, they represent a portion of the $2.4 million of total transaction costs incurred to complete the end-of-lease purchases of SGS Unit 1 made by TEP in December 2014 and January 2015.

Q. Please explain further what these costs represent.

A. Certainly. The total transaction costs of $2.4 million, which are listed as "acquisition fees" on page 7 of Confidential Exhibit KCH-19 attached to Mr. Higgins' Direct Revenue Requirement Testimony, represent transaction costs that were incurred by TEP to exercise the fair market value purchase options at the end of the SGS Unit 1 leases. They included professional appraisal fees, the legal costs of seeking confirmation of the appraisal in Federal Court, and the legal costs associated with the preparation and review of closing documents for the purchases completed in December 2014 and January 2015. Since these were costs incurred by TEP in connection with purchases of a 35.4% interest in SGS Unit 1, they were capitalized by the Company and included in the test-year balance of plant-in-service. The $919,042 of legal costs cited by Mr. Higgins represents only a portion of the total $2.4 million in transaction costs. The value of $919,042 was provided to Mr. Higgins by TEP as an estimate of the legal costs incurred in connection with the 50.5% share of SGS Unit 1 owned by Alterna and one other co-owner. However, since all of the SGS Unit 1 lessors participated as a single group in the appraisal process, as well as the appraisal confirmation proceeding that followed, these were costs that the Company would have incurred regardless of whether TEP ended up purchasing a single leased interest or all of the leased interests from the lessors. As such, these costs were properly classified as a cost of acquiring the 35.4% interest in SGS Unit 1 in December 2014 and January 2015.

VI. RATE BASE TREATMENT OF TEP HEADQUARTERS BUILDING.

Q. Please summarize the recommendation of AECC witness Kevin Higgins with respect to the TEP headquarters building.

A. Mr. Higgins recommends that TEP be allowed to earn only a cost of debt on the headquarters building, instead of the WACC which includes an equity return on the Company's invested capital.

Q. What rationale does Mr. Higgins offer for denying TEP an equity return on its investment in the headquarters building?

A. He basically reiterates the same concern he had in TEP's last rate case, which is a belief that the headquarters building is somehow less valuable in providing service to customers than other utility assets.

Q. Do you agree with his position?

A. No, I do not. Office space is a necessary part of providing retail electric service. It is simply unrealistic to assume that any utility of TEP's size could operate without the essential support services housed in the Company's headquarters building. Those support services include engineering, human resources, information technology, budgeting and procurement, accounting and finance, legal support and many other services needed to run a modern electric utility.

Q. Is the Company's headquarters building fully utilized?

A. Yes. It is essentially at full capacity, even with the addition of more workstations and a supplemental parking area. As of June 17, 2016, 92% of the workstations (507 out of 552) were occupied by TEP employees or contractors. Additionally, 123 offices were occupied by employees, bringing the total building occupancy to 630 employees and

contractors.

Q. Did the Company agree to earn only a cost of debt on its headquarters building investment in its last rate case?

A. Yes. That compromise was one of many that were made by all parties to TEP's last rate settlement agreement.

Q. What were the financial consequences of that compromise?

A. By limiting the return on the headquarters investment to the cost of debt, the Company's rate increase was $2.4 million lower than it otherwise would have been. Assuming new rates from the current case are not implemented until January 2017, the Company will have foregone approximately $8 million in revenues over a three and one-half year period, resulting in approximately $5 million in lower after-tax earnings. From a financial standpoint, that is roughly equivalent to an $8 million (or 12%) disallowance of the $66 million original cost (ACC jurisdictional amount) of the headquarters building.

Q. What would the financial consequences be if Mr. Higgins' recommendation were adopted in this rate case?

A. According to Mr. Higgins, it would reduce the Company's annual non-fuel revenue requirement by $3.5 million. Assuming the Company's new rates stay in effect another three and one-half years, TEP would be foregoing another $12 million in revenues and approximately $7 million in after-tax earnings. In nominal dollar terms, that would increase the implied disallowance of the Company's headquarters investment to approximately $20 million, or 30% of the original cost. Absent any showing of imprudence or unreasonableness on TEP's part, such a disallowance is clearly unwarranted.

Q. Please summarize the recommendation of RUCO witness Frank Radigan with respect to the TEP headquarters building.

A. Mr. Radigan recommends removing the headquarters building from rate base, and substituting a "market based" lease rate in the Company's revenue requirement.

Q. What explanation does Mr. Radigan have for removing the TEP headquarters building from rate base?

A. The gist of his argument may be found on page 40 of his Direct Revenue Requirement Testimony, where he states the following:

> Given that the new headquarters building was built primarily for purposes of the Holding Company and for ratemaking purposes, it should be assumed to be owned by the Holding Company and TEP should pay no more than the going market rate.

Q. Is this a new position taken by RUCO?

A. No, it is the same argument made by Mr. Radigan and another RUCO witness in TEP's last rate case.

Q. Is there any merit to his argument that TEP's parent company, UNS Energy Corporation ("UNS Energy"), should be deemed to be the owner of the building and therefore a lessor to TEP?

A. No. While UNS Energy certainly considered the possibility of owning the building, no compelling reason was identified that would justify such an added layer of complexity. Specifically, one of the options considered was the establishment of a special purpose entity under UNS Energy that would have owned the building and leased it to TEP. That particular structure was considered in order to realize federal income tax credits available for community development projects. Had the tax credits been available in sufficient quantity, they could have materially lowered the net cost of the project to UNS Energy, and by extension, to TEP. However, it was ultimately determined, with the assistance of

an outside consultant, that the tax credits would be difficult to obtain in the amounts needed to justify the complex legal and financial structure required to monetize the credits. Absent any cost advantage to owning the building at UNS Energy, the decision was made to own the building at TEP, the largest subsidiary of UNS Energy and the company that would benefit the most from a new headquarters building.

Q. Does UNS Energy have any operations of its own?

A. No. UNS Energy is a holding company with no business operations of its own. It was formed to own all of the common stock of TEP, UniSource Energy Services (the parent company of UNS Electric, Inc. and UNS Gas, Inc.), UniSource Energy Development Company ("UED") and Millennium Energy Holdings, Inc. ("MEH"). UED and MEH conduct business as unregulated affiliates of TEP, while UNS Electric, Inc. and UNS Gas, Inc. are regulated utilities with rates set by this Commission. The costs of common facilities, such as the TEP headquarters building, are allocated to each of these companies based on established formulas approved by the Commission. Therefore, TEP's retail customers bear only those facility costs properly allocable to the Company's retail jurisdictional business.

Q. What benefits have TEP and the community realized as a result of the headquarters building?

A. Consolidating most of TEP's support services in a single location has been very positive in terms of employee productivity and interaction. Additionally, relative to working in outdated facilities and portable modular buildings, the new headquarters building has had a beneficial impact on employee morale and recruiting. Having access to large conference room facilities has also improved the Company's outreach efforts with various community stakeholders and professional organizations. Lastly, I would note that TEP's investment and employee relocation was hugely beneficial to the

redevelopment of downtown Tucson, an urban area that was in sore need of new economic activity.

VII. FINANCIAL CONDITION OF TEP.

Q. How does IBEW witness Scott Northrup characterize TEP's financial condition?

A. On page 5 of his Direct Testimony, he refers to TEP's financial situation as being "shaky."

Q. Do you agree with Mr. Northrup's characterization?

A. No. As described in my Direct Testimony, TEP currently has solid investment-grade credit ratings of "A3" from Moody's and "BBB+" from Standard & Poor's. Furthermore, the Company has improved its balance sheet considerably over time through the retirement of debt and capital lease obligations, the retention and reinvestment of earnings, and the infusion of equity capital from its parent company UNS Energy.

Q. On page 11 of his Direct Testimony, Mr. Northrup also states that the Commission should "pay special attention to whether UNS is being inappropriately enriched at the expense of TEP and, in turn, its patrons." Is such a concern warranted?

A. No. The Fortis Merger Order approved by the Commission in 2014 contains a large number of safeguards that ensure against any "inappropriate enrichment" of UNS Energy by TEP. For example, there is a limitation on the dividends that TEP can pay to its parent company, and a prohibition against any guarantees of parent company debt by TEP. Further, it should be noted that since Fortis Inc. acquired UNS Energy in 2014, TEP has received cash contributions of equity capital from UNS Energy in amounts that greatly exceed the dividends paid by TEP to UNS Energy. This is one of the means by which

TEP has been able to improve its balance sheet and credit ratings over time.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

Exhibit KCG – R – 1

Tucson Electric Power Company
Capital Structure as of 12/31/15 and 3/31/16
(Thousands of Dollars)

Line No.	Capital Source	Capitalization Amount	Capitalization Percent
	12/31/2015		
1	Short-Term Debt	$0	0.00%
2	Long-Term Debt - Net	1,443,063	49.45%
3	Common Stock Equity	1,474,935	50.55%
4	Total Capital	$2,917,998	100.00%
	3/31/2016		
5	Short-Term Debt	$0	0.00%
6	Long-Term Debt - Net	1,443,780	49.48%
7	Common Stock Equity	1,474,298	50.52%
8	Total Capital	$2,918,078	100.00%

Note: The balance of Long-Term Debt is stated net of the unamortized balance of debt discount and issuance expense, per Exhibit KCG-5.

Exhibit KCG – R – 2

Tucson Electric Power Company
Cost of Debt as of 12/31/15 and 3/31/16
(Thousands of Dollars)

Line No.	Description		12-31-2015 Outstanding	12-31-2015 Annual Interest	12-31-2015 Cost Rate	3-31-2016 Outstanding	3-31-2016 Annual Interest	3-31-2016 Cost Rate	Line No.
	Fixed Rate Taxable Bonds								
1	5.15% Series due 2021		$250,000	$12,875		$250,000	$12,875		1
2	3.85% Series due 2023		$150,000	$5,775		$150,000	$5,775		2
3	5.00% Series due 2044		$150,000	$7,500		$150,000	$7,500		3
4	3.05% Series due 2025		$300,000	$9,150		$300,000	$9,150		4
5	Total Fixed Rate Taxable Bonds		850,000	35,300	4.15%	850,000	35,300	4.15%	5
	Fixed Rate Tax-Exempt Bonds								
6	4.500% 2012 Apache A		177,000	7,965		177,000	7,965		6
7	5.850% 2012 Pima A		16,465	741		16,465	741		7
8	4.000% 2013 Pima A		90,745	3,630		90,745	3,630		8
9	4.950% 2009 Pima A (San Juan)		80,410	3,980		80,410	3,980		9
10	5.125% 2009 Coconino A		14,700	753		14,700	753		10
11	5.250% 2010 Pima A		100,000	5,250		100,000	5,250		11
12	Total Fixed Rate Tax-Exempt Bonds		479,320	22,319	4.66%	479,320	22,319	4.66%	12
	Variable Rate Tax-Exempt Bonds								
13	2013 Apache A		100,000	810		100,000	838		13
14	2010 Coconino A		36,700	347		36,700	352		14
15	Total Variable Rate Tax-Exempt Bonds		136,700	1,157	0.85%	136,700	1,191	0.87%	15
16	Total Long-Term Debt	(a)	1,466,020	58,776	4.01%	1,466,020	58,810	4.01%	16
17	Unamortized Debt Discount, Premium and Expense and Loss on Reacquired Debt		(22,957)			(22,240)			17
18	Amortization of Debt Discount and Expense and Loss on Reacquired Debt			3,010			3,021		18
19	Credit Facility Commitment Fees			313			313		19
20	Total Long-Term Debt - Net		$1,443,063	$62,099	4.30%	$1,443,780	$62,143	4.30%	20
21	Total Short-Term Debt		$0	$0	N/A	$0	$0	N/A	21

Rebuttal Testimony of

Ann E. Bulkley

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIR
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-1933A-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

Rebuttal Testimony of

Ann E. Bulkley

on Behalf of

Tucson Electric Power Company

July 25, 2016

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EXHIBITS:

Exhibit AEB-R-1 Fair Value Rate of Return - Arizona Staff Methodology
Exhibit AEB-R-2 Correction of Mr. Gorman's Fair Value Cost Rate

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Ann E. Bulkley, and I am a Vice President of Concentric Energy Advisors, Inc. ("Concentric"). My business address is 293 Boston Post Road West, Suite 500, Marlborough, MA 01752.

Q. On whose behalf are you submitting this Rebuttal Testimony?

A. I am submitting this Rebuttal Testimony on behalf of Tucson Electric Power Company ("TEP" or the "Company").

Q. Did you previously submit testimony in this proceeding?

A. Yes. I submitted Direct Testimony regarding the appropriate Return on Equity ("ROE"), capital structure, and Fair Value Rate of Return ("FVROR") for TEP in this proceeding.

Q. What is the purpose of your Rebuttal Testimony?

A. The purpose of my Rebuttal Testimony is to respond to the cost of capital issues within the Direct Testimonies of Mr. David C. Parcell on behalf of the Utilities Division Staff (the "Staff") of the Arizona Corporation Commission (the "Commission"), Mr. Robert B. Mease on behalf of the Residential Utility Consumer Office ("RUCO"), Mr. Michael P. Gorman on behalf of the U.S. Department of Defense and all other Federal Executive Agencies ("DOD"), and Mr. Gregory W. Tillman on behalf of Wal-Mart Stores, Inc. and Sam's West, Inc. (collectively, the "Opposing ROE Witnesses").

Q. Have you prepared any exhibits to support your analysis and recommendations?

A. Yes. My recommendations are supported by the data presented in Exhibits AEB-R-1 through AEB-R-2, which have been prepared by me or under my direction.

Q. How is the remainder of your Rebuttal Testimony organized?

A. The remainder of my Rebuttal Testimony is organized as follows:

- In Section II, I provide a summary and overview of my Rebuttal Testimony.
- In Section III, I provide a summary of capital market conditions and their effect on the cost of equity for TEP.
- In Section IV, I respond to Mr. Parcell's analyses and recommendations.
- In Section V, I respond to Mr. Mease's analyses and recommendations.
- In Section VI, I respond to Mr. Gorman's analyses and recommendations.
- In Section VII, I respond to Mr. Tillman's recommendations.
- Finally, in Section VIII, I summarize my conclusions and recommendations.

II. SUMMARY AND OVERVIEW

Q. Please provide an overview of the Opposing Witnesses ROE recommendations in this proceeding.

A. As shown in Table 1, the Opposing ROE witnesses have recommended ROE levels in a narrow range from 9.20 percent to 9.35 percent.[1] The FVROR recommendations of the Opposing ROE witnesses range from 5.00 percent to 5.20 percent.

[1] Mr. Tillman recommends an ROE not to exceed 9.50 percent based on the recent settlement agreement in UNS Electric.

Table 1: Recommended ROE Ranges and Point Estimates of the Opposing ROE Witnesses

Witness	Recommended ROE Range	Original Cost ROE Recommendation	FVROR Recommendation
Mr. Parcell	9.20%-9.50%	9.35%	5.00%
Mr. Mease	7.91%-9.65%	9.20%	5.20%
Mr. Gorman	8.90%-9.70%	9.30%	5.00%
Mr. Tillman	N/A	Max of 9.50%	NA

Q. Please provide a brief overview of your response to Staff witness Parcell with respect to the appropriate ROE for TEP.

A Mr. Parcell recommends an ROE of 9.35 percent and relies on a 0.70 percent Fair Value Increment for TEP.[2] Mr. Parcell performs a Discounted Cash Flow analysis, Capital Asset Pricing Model analysis, and Comparable Earnings analysis to estimate the cost of equity for TEP.[3] He contends that his ROE recommendation of 9.35 percent is reasonable based on his view that the current low interest rate environment has reduced the cost of equity for electric utility companies. As discussed in my Direct and Rebuttal testimonies, while interest rates in recent years have been at historically low levels as a result of Federal Reserve monetary policy, current and projected capital market conditions fully support an ROE above 9.35 percent. The specific areas of disagreement with Mr. Parcell's ROE analyses are summarized below:

- Mr. Parcell's ROE estimation methodologies result in a lower recommended ROE than the annual average ROEs authorized for 2014 to 2016 for vertically integrated electric companies; and, is lower than each of the individual returns authorized for vertically integrated electric utilities during that period, with the exception of one company, Kansas City Power and Light, which was authorized a return of 9.30 percent in 2015.

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2 Direct Testimony of David C. Parcell, at 3 and 49. Mr. Parcell's range of return on the Fair Value Increment is between 0.00 percent and 1.42 percent. See Direct Testimony of David C. Parcell at 45, and 48.

3 *Ibid.*, at 2-3.

- As shown in DCP-1, Mr. Parcell provides a recommended range of equity returns of 9.2 percent, 9.35 percent and 9.5 percent. The majority of the results of Mr. Parcell's analyses fall significantly below his recommended range of equity returns. Therefore, Mr. Parcell's ROE recommendation does not appear to be directly tied to his analytical results, but rather is based on his judgment regarding the appropriate ROE for TEP. Mr. Parcell's recent ROE recommendations in other proceedings have been within a narrow range, regardless of the relative risk profile of the subject utility.[4] Mr. Parcell has not considered the additional risks that TEP is exposed to, relative to the proxy group, which are described at length in my Direct Testimony.[5]
- Mr. Parcell's CAPM analysis produces results ranging from 6.5 percent to 6.8 percent, at least 255 basis points below his final recommended ROE and 250 to 280 basis points below the lowest authorized ROE for any integrated electric utility. Despite these facts, Mr. Parcell suggests that these results should still be considered as a factor in setting the ROE for TEP.[6] Mr. Parcell acknowledges that his unreasonably low results are related to the assumptions he uses for the market risk premium of 5.75 percent. While the analysis he presents in Schedule 8 shows the market risk premium increasing since the 2008 financial market collapse, and the 2014 market risk premium at nearly 300 basis points higher than the pre-collapse levels, Mr. Parcell suggests that investors have come to expect lower equity returns and risk premiums.[7] Mr. Parcell's analysis of the equity risk premium appears inconsistent with investor expectations and the risk factors in the market since the 2008 financial market turmoil. It is not reasonable to expect

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4 *See* Municipal Light and Power Department Anchorage, Docket U-13-184, filed May 2014 with recommended ROE of 9.5%; Artesian Water Company, Docket 11-132, filed September 2014 for ROE of 9.10%; United Water Pennsylvania Inc., Docket R-20152462723, filed April 2015 for ROE of 9.25%; Southwestern Public Service, Docket 43695, filed May 2015 for ROE of 9.4%; and Oklahoma Gas and Electric Company, Docket 201500273, filed March 2015 for ROE of 9.0%.

5 Direct Testimony of Ann E. Bulkley, at 44-51.

6 Direct Testimony of David C. Parcell, at 34.

7 Direct Testimony of David C. Parcell, at 33.

that in 2008, as financial institutions filed bankruptcy and returns in the stock market were negative, that the risk premium for holding equity would be *lower* than in more stable market conditions.

- In addition, Mr. Parcell's analysis does not reflect the inverse relationship between the equity risk premium and interest rates. When interest rates are anomalously low, as they are today, it is important to either use a normalized interest rate that is more characteristic of the long term average, or if one chooses to use a current interest rate, it should be used in conjunction with a forward-looking market risk premium that reflects the current interest rate environment and the inverse relationship of the market risk premium to interest rates.
- Mr. Parcell's DCF and comparable earnings analyses are heavily reliant on historical data which are subject to a host of accounting and operational issues that have no bearing on forward-looking return projections. To the extent that past historical occurrences remain relevant, they are already incorporated in analyst projections. By relying on historical data, Mr. Parcell is placing unwarranted weight on the effect of historical occurrences.
- Mr. Parcell claims that my analysis is biased upward in a manner that inflates my return recommendation. He takes exception to my use of analyst forecasts of earnings growth, claiming that analysts provide inaccurate and biased forecasts; he takes exception to my use of projected interest rates and my forward risk premium calculation, claiming that the ultimate application of those inputs results in a return that is too high. Although, Mr. Parcell criticizes my reliance on analysts' projections of earnings growth for my DCF analysis, it is solely the earnings growth rate in Mr. Parcell's DCF analysis that establishes the lower bound of his range. All of the other growth rate estimates that Mr. Parcell considered produce DCF results that range from 6.7 percent to 8.2 percent, which

are significantly below his final DCF result of 9.20 percent and his recommended ROE of 9.35 percent.

Q. Please summarize your response to Staff witness Parcell with respect to the FVROR.

A The methodology that Staff relies on to develop the FVROR is consistent with the methodology that was used in my Direct Testimony (i.e., assigning a return to the Fair Value Increment of one half the real risk-free rate). However, Staff's proposed cost rate for the Fair Value Increment is lower than what is reflective of current market conditions because of the nominal risk-free rate Mr. Parcell has relied on. Simply updating the nominal risk-free rate used in Staff's FVROR to the short-term nominal risk-free rate used in the analysis presented in my Direct Testimony increases the return on the Fair Value Increment from 0.70 percent to 1.25 percent.

Q. Please summarize your response to RUCO witness Mease's ROE recommendation for TEP.

A. As shown in Table 1 above, the range of ROE results presented by Mr. Mease is between 7.91 percent and 9.65 percent, which represents the range of results for his Constant Growth DCF model. Mr. Mease's recommended ROE of 9.20 percent is 80 basis points below the 10.00 percent return that was authorized for TEP in Docket No. E-01933A-12-0291 and 45 to 55 basis points below the average annual returns that have been authorized for integrated electric utilities since 2014. Mr. Mease's recommended ROE is not a reasonable estimate of the cost of equity for TEP for the following reasons:

- Mr. Mease's recommendation to lower TEP's currently authorized ROE by 80 basis points is based on the use of recent interest rates and fails to consider the expectation for interest rates over the period that TEP's rates will be in effect. As

discussed in my Direct Testimony, forward-looking data demonstrate that investors expect an increase in interest rates. As shown by the Bond Yield Risk Premium analysis, there is a positive relationship between interest rates and ROEs. Therefore, using forward-looking data would suggest an increase in the ROE, not the decrease proposed by Mr. Mease.

- The results of Mr. Mease's CAPM analysis range from 7.48 percent to 8.51 percent. Mr. Mease relies on the 3 month average for the 30-year Treasury bond yield for his risk free rate and a market risk premium of 6.91 percent, for which he has provided no source or explanation. As stated previously with respect to Mr. Parcell, when interest rates are anomalously low, as they are today, it is important to either use a normalized interest rate that is more characteristic of the long term average, or a current interest rate in conjunction with a forward-looking market risk premium that reflects the current interest rate environment and the inverse relationship of the market risk premium to interest rates.
- Mr. Mease's recommended FVROR is calculated by removing inflation from the Weighted Average Cost of Capital ("WACC") that would be applied to an OCRB. In order to properly calculate the FVROR, consistent with Commission precedent, one half of the real risk-free rate should be used as the cost rate that is applied to the FV increment.

Q. Please summarize your response to DOD witness Mr. Gorman's ROE and capital structure recommendations for TEP.

A. Mr. Gorman's ROE recommendation of 9.30 percent does not provide a reasonable estimate of TEP's cost of equity.

- Mr. Gorman's 9.30 percent ROE recommendation is not comparable to the average recent ROE awards for vertically-integrated electric utilities and would

not allow TEP to effectively compete for capital with other investments of comparable risk.

- The results of Mr. Gorman's DCF analysis are significantly below the range of results he establishes as reasonable. While Mr. Gorman suggests that a return of 9.30 percent is reasonable for TEP, his mean Constant Growth DCF results suggest a return of 7.72 percent (using sustainable growth rates) and 8.71 percent (using analysts' earnings per share growth rates). These results are 59 to 158 basis points below any authorized ROE for a vertically integrated electric utility and are not reasonable. In my Direct and Rebuttal testimonies, I explain how the DCF model is being affected by anomalous market conditions and propose certain adjustments within the range of results.
- Mr. Gorman's Multi-Stage DCF analysis produces a return of 7.99 percent that is within the range established by his constant growth DCF results. The unreasonably low result from this methodology is based on his forecast long-term growth rate of 4.20 percent. Using a multi-stage DCF analysis and Mr. Gorman's price and near-term growth rate assumptions, a 9.30 percent ROE, which is recommended by Mr. Gorman, would require a long-term GDP growth rate of 5.84 percent, which is 44 basis points higher than the long-term GDP growth rate relied on in my analysis.
- The low end of Mr. Gorman's range of CAPM results of 8.01 percent is substantially below any authorized ROE for a vertically integrated electric utility in the U.S. in the last 25 years, while the upper end of the range of 9.44 percent is approximately 40 basis points lower than the average authorized ROEs for integrated electric utilities since January 2015. Mr. Gorman assigns 75 percent weight to the high CAPM results and 25 percent to the low CAPM results to arrive at an average CAPM result of 9.10 percent.

- Mr. Gorman's low market risk premium of 6.0 percent does not reflect the inverse relationship between the equity risk premium and interest rates. Mr. Gorman's high market risk premium of 7.90 percent is 71 basis points lower than the low end of the forward-looking MRPs in my CAPM analysis. While Mr. Gorman criticizes my MRPs as being too high, relying on the low end MRP in my analysis and Mr. Gorman's average beta of .75 results in a return of 9.95 percent which is within the range of recently authorized ROEs.
- Mr. Gorman produces two risk premium analyses, one based on long-term Treasury yields and another based on A-rated utility bond yields. In both cases, he calculates the difference between the average awarded electric ROEs in a given year, less the respective bond yield in each year from 1986-2015. Mr. Gorman bases his risk premium estimates on an average of the rolling 5-year average for each risk premium calculation. Mr. Gorman's analysis shows that the risk premium has been steadily increasing over his analytical period. Mr. Gorman offers no evidence as to why it is appropriate or relevant to rely on an equity risk premium as dated as 1986 in establishing a forward-looking ROE.
- Mr. Gorman's range of results is framed by the average of his Constant Growth DCF analysis and his CAPM analysis on the low end and by his Risk Premium analysis on the high end. Mr. Gorman fails to recognize that the DCF model is producing results that are not corroborated by the CAPM, the Bond Yield Plus Risk Premium analysis, or ROE awards for integrated electric utilities in other jurisdictions.
- Mr. Gorman's recommended capital structure consisting of 48.69 percent common equity and 51.31 percent long-term debt should be rejected. As discussed in the Rebuttal Testimony of Company witness Kentton Grant, shortly after the test-year TEP achieved, and has since maintained, a capital structure consistent with the proposed capital structure of 50.03 percent common equity

and 49.97 percent long-term debt. The Company's proposed equity ratio is well below the proxy group average common equity ratio of 54.00 percent. [8]

- While Mr. Gorman relies on a methodology to estimate the FVROR that is similar to the methodology that I used in my Direct Testimony, Mr. Gorman's analysis relies on current and short-term projected nominal risk-free rates and a long-term projection of inflation. Since interest rates are expected to increase, the effect of using these two different time periods to estimate the real risk-free rate is that the nominal risk-free rate and the inflation factor are not consistent. Simply updating the nominal risk-free rate to be consistent with the projected time period relied on in estimating the inflation factor increases the return on the fair value increment 61 basis points above the estimate provided by Mr. Gorman.

Q. Please summarize your response to Wal-Mart witness Mr. Tillman with respect to the appropriate ROE for TEP.

A. Mr. Tillman does not recommend a specific ROE for TEP. Rather, he suggests that the Commission should examine the Company's request in light of the customer impact of the resulting revenue requirement increases and recent ROE awards for electric utilities approved by commissions nationwide.[9] Mr. Tillman testifies that the average authorized ROE for vertically-integrated electric utilities from 2013-2016 has been 9.89 percent, and that the trend in recent years has been toward declining allowed returns on equity.[10] Mr. Tillman does not take into consideration the range of those returns nor does he consider the comparative risk of TEP and the companies in his data set. Mr. Tillman ultimately recommends that the Commission not allow an ROE higher than the 9.50 percent ROE recently stipulated to by UNS Electric Inc. unless there is a showing that economic or

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8 *See* Exhibit AEB-9, p. 1 of 2 proxy group average for the eight quarters ending Q1 2015.
9 Direct Testimony of Gregory Tillman, at 8.
10 *Ibid.*, at 12.

capital market conditions are significantly different from the time of the stipulation.[11] However, Mr. Tillman does not discuss the fact that this stipulated ROE was only one aspect of a complicated revenue requirement stipulation entered into by several of the parties to the UNS Electric rate case, nor does he discuss the significant difference in the risk profile between UNS Electric and TEP.

Q. Several of the Opposing ROE witnesses suggest that the Commission should consider ROE awards in other jurisdictions as a practical benchmark for assessing ROE recommendations. Do you agree?

A. I agree that ROE awards in other jurisdictions provide a useful benchmark to assist the Commission in assessing overall reasonableness and send an important signal to investors regarding whether there is regulatory support for financial integrity, dividends, and financial growth, and fair compensation for business and financial risk. The cost of capital represents an opportunity cost to investors. If higher returns are available for other investments of comparable risk, investors have the incentive to direct their capital to those investments. Thus, an ROE significantly below authorized ROEs in other jurisdictions can inhibit the Company's ability to attract capital on reasonable terms for investment in Arizona.

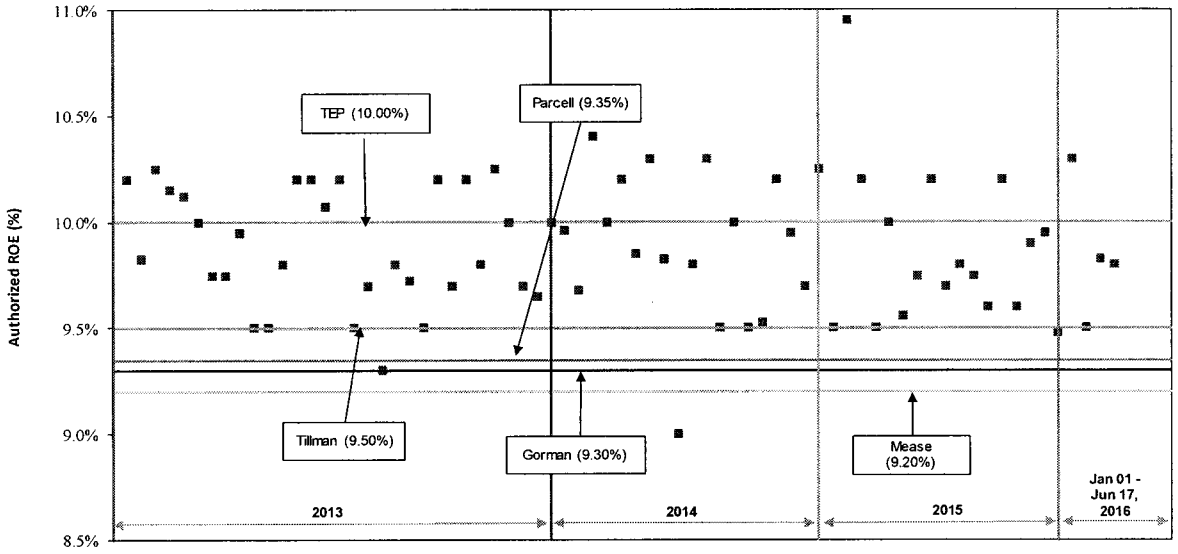
Q. How do the ROE recommendations of the Opposing ROE witnesses compare to the allowed ROEs for other integrated electric utilities?

A. As shown in Chart 1, the ROE recommendations of Mr. Mease (9.20 percent), Mr. Gorman (9.30 percent), Mr. Parcell (9.35 percent) and Mr. Tillman (no higher than 9.50

[11] *Ibid.*, at 14.

percent) are below the average authorized ROE for vertically-integrated electric utilities between January 1, 2012 and May 31, 2016.

Chart 1: Authorized ROEs for Integrated Electric Utilities
January 1, 2013 – June 17, 2016[12, 13]



Q. What is your conclusion regarding the appropriate cost of equity for the Company?

A. While the average authorized ROE has declined, there is variability in authorized ROEs. Based on the risk factors identified for TEP, I agree with the Opposing ROE witnesses that it is appropriate to set the ROE above the mean of the analytical results. As discussed in the Rebuttal Testimony of TEP witness Kentton Grant, the Company has modified its non-fuel revenue requirement to reflect an ROE of 10.00 percent, which is at the low end of my recommended range. I conclude that the Company's requested return of 10.00 percent is conservative based on the results of the ROE estimation methodologies, the recently authorized returns for vertically integrated electric utilities, company-specific risk factors and investors' expectation of market conditions over the

12 Source: SNL Energy, Inc.

13 It is important to note that the 2016 authorized ROE represents approximately 6 months of data and is a very small sample, including only four data points that provide specific authorized ROEs outside of the context of a more comprehensive settlement.

period that rates will be in effect. ROEs at the levels proposed by the Opposing ROE witnesses are not reasonable and do not meet the standards established in *Hope* and *Bluefield* for a fair return.

III. CAPITAL MARKET CONDITIONS AND THEIR EFFECT ON THE COST OF EQUITY FOR TEP

Q. How have the Opposing ROE witnesses taken into consideration the effect of economic and capital market conditions on the cost of equity for TEP?

A. Messrs. Parcell, Mease and Gorman cite the current low interest rate environment as an important consideration in the cost of equity and as support for their low ROE recommendations. Mr. Tillman cites the recent trend of declining average ROE awards for regulated electric utilities. The Opposing ROE witnesses' recommendations, however, are based on capital market conditions over the past few years, and do not adequately consider the changes that have occurred in recent months or the prospects for financial markets on a going-forward basis. In my view, it is not reasonable to dismiss current and projected market conditions or to base the authorized ROE for TEP in this proceeding on previous economic and financial market conditions.

The ROE that is authorized in this proceeding is intended to provide a reasonable return to investors over the forward-looking period during which these rates will be in effect. For that reason, it is important to consider the prospects for financial markets during that period. As discussed in my Direct Testimony, extraordinary and persistent federal intervention in capital markets has artificially lowered government bond yields since the Great Recession of 2008-09, as the Federal Reserve has used monetary policy (both reductions in short-term interest rates and purchases of Treasury bonds and mortgage

backed securities) to stimulate the U.S. economy.[14] This highly accommodative monetary policy has resulted in government bond yields that have been artificially suppressed by the Federal Reserve. However, market data suggest that investors perceive greater risk in the current market environment, and there is a great deal of uncertainty around the path and timing of interest rate movements. Therefore, it is important to consider the current and prospective market conditions and investor expectations, all of which may put upward pressure on utility capital costs going forward.

Q. Do you agree with the Opposing ROE witnesses that changes in utility bond yields support a lower authorized ROE for TEP?

A. No, I do not. During periods of equity market volatility, as risk aversion increases, investors seek out the relative safety of Treasury securities and other relatively low-risk debt securities, essentially bidding up prices and forcing down yields. Accordingly, the current yields on U.S. Treasury securities are being driven by a temporary flight to quality by investors and the Federal Reserve's highly accommodative monetary policy. The current low bond yields are not being driven by typical bond market participants. In addition, there is a well-established inverse relationship between equity risk premiums and prevailing risk free rates.[15] Equity investors tend to require higher risk premiums during periods of lower interest rates. Thus, low interest rates set by the Federal Reserve are not reliable indicators of investment risk or the cost of capital in equity markets. The Opposing ROE witnesses fail to recognize the inverse relationship between interest rates

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[14] Direct Testimony of Ann E. Bulkley, at 11-12.

[15] *See e.g.,* S. Keith Berry, "Interest Rate Risk and Utility Risk Premia during 1982-93," Managerial and Decision Economics, Vol. 19, No. 2 (March, 1998), in which the author used a regression analysis, including using allowed ROEs as the relevant data source, and concluded that there was an inverse relationship between equity risk premia and interest rates. *See* also Robert S. Harris, "Using Analysts' Growth Forecasts to Estimate Shareholders Required Rates of Return," Financial Management, Spring 1986, at page 66, and Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, "An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry," *Financial Management*, Volume 24, No. 3, Autumn 1995, at pages 89-95.

and the equity risk premium. As interest rates decrease, the equity risk premium increases to reflect the fact that investors are unwilling to invest in riskier equity assets, and instead prefer the relative safety of debt securities despite their current historically low yields. On that basis, I disagree that the current low level of utility bond yields indicates that the cost of equity for utilities is correspondingly low.

Q. Mr. Gorman views electric utilities as generally regarded as "safe haven" or "low risk" investments, and that investors will continue to provide an abundance of low cost capital to support utilities' capital programs.[16] What is your response?

A. There is no dispute that utilities are now, and typically have been, relatively lower risk investments than the market overall; that clearly is the case given that the proxy group Beta coefficients all are less than one.[17] However, my discussion of capital market conditions and risk sentiment indicators shows that investors are facing generally higher risks and that utilities, in particular, are not "low risk" investments. Specifically, the incremental credit spreads between Baa-rated and A-rated utility bonds, and the current level of uncertainty in global financial markets will likely result in higher credit spreads and risk premiums and may translate into higher equity capital costs for all U.S. companies, even A- and Baa-rated regulated utilities.

Q. What is the financial market's perspective on the likelihood for future increases in short-term interest rates by the Federal Reserve?

A. At present there is great uncertainty around the Federal Reserve's policy for future increases in short-term interest rates. In mid-December 2015, the Federal Reserve announced the first increase in short-term interest rates since the financial market

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16 Direct Testimony of Michael P. Gorman, at 9.

17 *See,* Schedule AEB-4.

collapse in 2008. In its statement, the Federal Reserve indicated that further increases in short-term interest rates would be gradual as the economy strengthens further and inflation rises from undesirably low levels. The July 2016 issue of the Blue Chip Financial Forecasts ("Blue Chip") surveyed leading economists and market participants concerning their views about the likelihood of future increases in short-term interest rates by the Federal Reserve. Blue Chip reported that 43.9 percent of market participants surveyed expected the Federal Reserve to raise short-term interest rates again no later than September 2016, and forecast that yields on 30-year Treasury bonds would increase to 4.30 percent between 2018 and 2022. [18,19]

However, recent changes in the global economy with Great Britain's vote to exit the European Union ("Brexit") has resulted in unsettled markets and heightened volatility. It is unclear at this time how this development will affect export markets and the overall growth of the U.S. economy, which again serves to increase market volatility and market risk. This sort of uncertainty in global financial markets may have an effect on interest rates, risk premiums, and credit spreads, affecting the return requirements of investors.

Q. What indications are there that investor risk sentiment is increasing?

A. Even before the Brexit vote, credit spreads were increasing. As shown in Chart 2 of my Direct Testimony, credit spreads between government and utility bonds had increased to nearly 200 basis points and were wider than when the company had its last rate case. The spread between Baa-rated utility debt and 30-year Treasury bonds is now 253 basis points, an increase of 61 basis points since the filing of my Direct Testimony.

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[18] Blue Chip Financial Forecasts, Volume 35, No. 7, July 1, 2016, at 14.
[19] Blue Chip Financial Forecasts, Volume 35, No. 6, June 1, 2016, at 14.

Table 2: Credit Spreads

BOND YIELDS	5/31/16 CURRENT CREDIT SPREADS	7/31/15 FILING OF DIRECT	6/27/2013 TEP 2013 RATE DECISION	GREAT RECESSION 12/3/2007-6/30/2009
Moody's Baa-Rated - Moody's A Rated Utility Bond	1.11%	0.76%	0.53%	0.80%
Moody's Baa-rated Utility Bond – 30-year U.S. Treasury	2.53%	1.92%	1.59%	3.03%
Moody's A-rated Utility Bond – 30-year U.S. Treasury	1.42%	1.16%	1.06%	2.23%

As discussed in my Direct Testimony, increasing credit spreads are an indicator that bond investors are becoming more concerned about future economic conditions.[20]

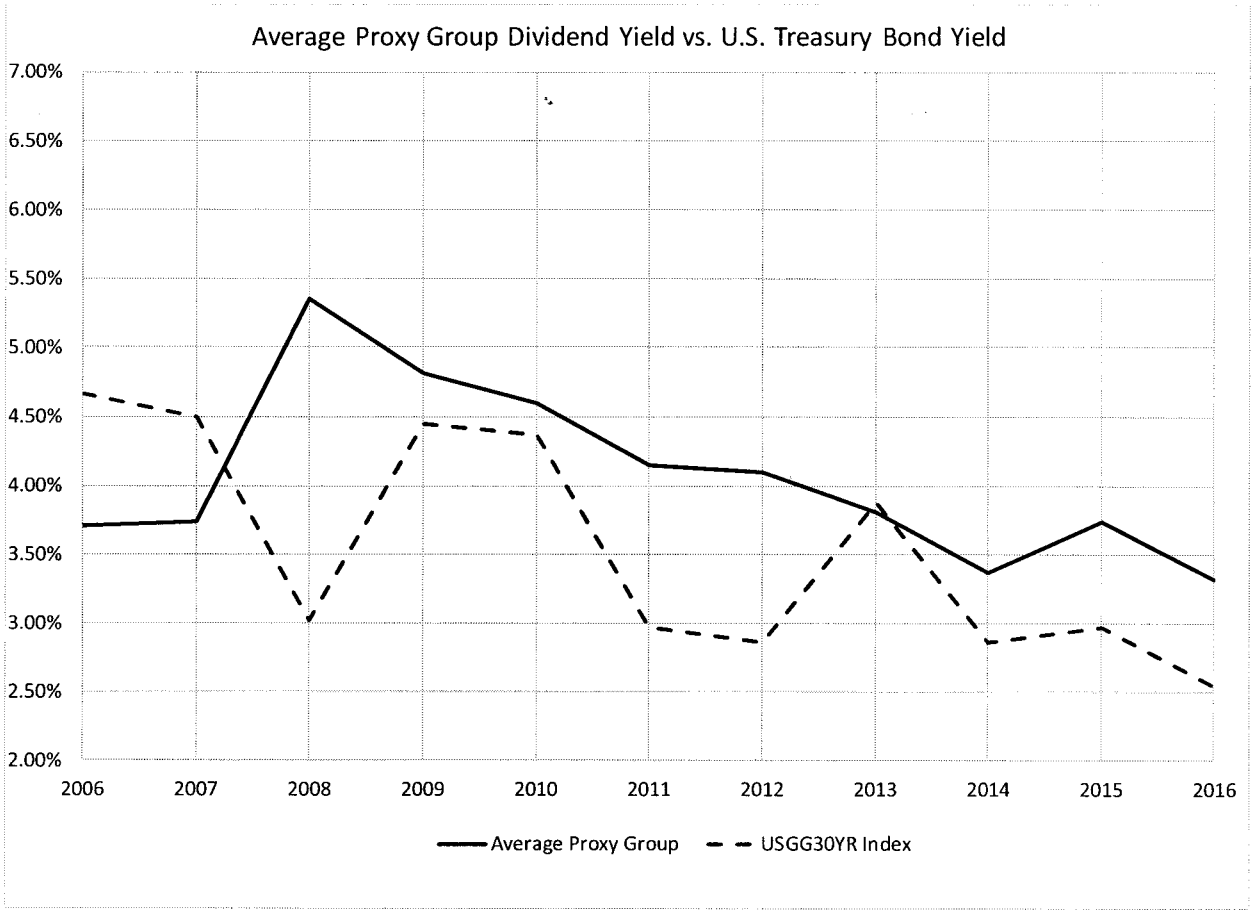
Q. Are expectations for higher interest rates, wider credit spreads, lower dividend yields, and high stock valuations for utility companies already reflected in the cost of equity produced by a DCF analysis?

A. In theory, and during times of general economic and capital market stability, I believe that the DCF analysis reflects market conditions and investor expectations. However, in the current market environment, the DCF model results are being distorted by the uncommonly low level of interest rates. Value Line recently observed that dividend yields for electric utilities are currently well below the historical average, and that high valuations on utility shares are not expected to be sustained over the three-to-five year period.[21] In order to assess how low interest rates are affecting the dividend yields for utility stocks, I have performed an analysis comparing the current dividend yield for the electric utilities in my proxy group (excluding those companies that are currently involved in merger activity) to the historical dividend yields for these same companies

[20] Direct Testimony of Ann E. Bulkley, at 17.
[21] Value Line Investment Survey, Electric Utility (West) Industry, April 29, 2016, at 2226.

from 2006-2016, as well as to yields on 30-year Treasury bonds in each year. Chart 2 presents the results of my analysis.

Chart 2: Average Proxy Group Dividend Yields and U.S. Treasury Bond Yields 2006 - 2016



As shown in Chart 2, the average dividend yield for the companies in my proxy group is at its lowest level since 2006, driven lower by yields on 30-year Treasury bonds and federal monetary policy.

Understanding the important role that dividend yields play in the DCF model, this is evidence that anomalous capital market conditions are causing the DCF model to

understate equity costs for regulated utilities at this time. The FERC has recently recognized this phenomenon, stating:

> As is discussed, infra, the level of the dividend yield affects the reliability of the DCF process when that level is lower than the level acceptable to investors that value utility stocks based on their estimated long-term dividend growth. The record creates cause for concern that during a period including the Study Period, investors valuing utility stocks based solely or primarily on their current yield bid the prices of the proxy group stocks up to levels that rendered their Total Returns unacceptable to investors that valued such stocks based on their estimated long-term dividend growth. For reasons set out below, this record evidence creates further cause for concern that placement of the MISO TOs' Base ROE at the Midpoint may not meet the requirements of Hope.[22]

The FERC also observed that due to anomalous conditions in capital markets (i.e., low Treasury bond yields) the midpoint results of the DCF model are not a reasonable estimate of the cost of equity at this time, stating:

> The yields of 10-year Treasury Bonds during the Study Period continue to reflect economic conditions that could render inputs to the DCF analysis unrepresentative. During the study period, the yields of 10-year Treasury Bonds averaged 2.21 percent. That yield was 38 basis points higher than the average yield of those bonds during the Opinion No. 531 study period, but 79 basis points below the 3.0 percent level that so concerned the Commission in Opinion No. 531. If the average 10-year Treasury-Bond yields for the Opinion No. 531 study period reflected economic conditions that could serve to render financial inputs into the DCF model unrepresentative, the average bond yields for the study period in this proceeding are close enough to the earlier yields to reflect the same conditions. Accordingly, the level of 10-year Treasury Bond yields during the Study Period create sufficient doubt regarding the representativeness of DCF inputs to warrant an examination of alternative metrics prior to making a final determination as to the level of the MISO TOs' Base ROE.[23]

In summary, the DCF model is not adequately reflecting expectations for higher rates, wider credit spreads, lower dividend yields and high valuations on utility shares at this

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[22] 155 FERC ¶ 63,030 (June 30, 2016) at para. 128.

[23] *Ibid.*, at paragraph 126.

time. Consequently, it is necessary to consider the results of other Risk Premium models and returns in other jurisdictions in order to assess the reasonableness of the DCF results and to determine where to set the appropriate return within the range of results.

Q. How should capital market conditions be considered in setting the ROE for TEP?

A. The expectations of equity investors and the overall risk sentiment in the market should be considered in setting the ROE for TEP. As a result of market uncertainty, utility share valuations are temporarily inflated due to investors' flight to quality, and correspondingly result in abnormally low dividend yields. Consequently, the DCF models will understate forward-looking equity returns, because share valuations are based on temporary circumstances. Other models, such as the Risk Premium analysis, which are sensitive to changes in interest rates, may provide better information for the utility cost of equity than that currently indicated by the DCF model. Further, as a result of higher credit spreads, increased market volatility and the potential for rising interest rates, it is reasonable to believe that the cost of capital for electric utilities such as TEP would be increasing, not decreasing. Based on similar data, regulators in other jurisdictions including the FERC, have determined that it is appropriate to consider the results of other models and to estimate the cost of equity toward the upper end of the range of results during periods of anomalous capital market conditions.

IV. RESPONSE TO STAFF WITNESS PARCELL

Q. Please summarize Staff witness Parcell's ROE recommendation.

A. Mr. Parcell recommends an ROE for TEP of 9.35 percent based on the results of his DCF, CAPM and Comparable Earnings analysis. This recommendation is 65 basis points lower than TEP's currently-authorized ROE of 10.00 percent. As support for his ROE

recommendation, Mr. Parcell cites the low interest rate environment in recent years, as well as the weak economic outlook for the next few years.

Q. What is your response to Mr. Parcell's testimony and recommendation concerning the Cost of quity?

A. Mr. Parcell's recommendation is unduly low in light of current and projected economic and capital market conditions, and is not consistent with recently-authorized ROEs for vertically-integrated electric utilities in other jurisdictions. Moreover, Mr. Parcell's recommended ROE does not appear to be the product of the vast majority of his analyses. The ranges he establishes are only loosely related to his analytical results. For example, he states that the high end of his range of 9.5 percent is based on his CE analysis; however, the highest ROE in that analysis is 9.3 percent. In summary, Mr. Parcell's recommendation appears to be highly subjective and based at least as much on his opinion as on his analyses. Furthermore, it is not clear whether Mr. Parcell has considered the full extent of TEP's operating risks, particularly those related to its generation portfolio. In his most recent testimonies, Mr. Parcell's recommendations have been within a tight range (between 9.0 and 9.4 percent), despite large differences in operating risks among the subject utilities (i.e. water utilities, vertically integrated electric utilities with differing generation portfolios, etc.).

Q. Is Mr. Parcell's ROE recommendation of 9.35 percent consistent with returns for integrated electric utilities in other jurisdictions across the U.S.?

A. No, it is not. As shown in Chart 1, Mr. Parcell's ROE recommendation of 9.35 percent is at the low end of the range of recent ROE awards for integrated electric utilities. In 2015-2016, the range of ROEs for vertically integrated electric utilities was 9.30 percent to 10.30 percent, with an average return of 9.72 percent. Forward-looking economic and

capital market conditions, as well as TEP's additional business risks, support an authorized ROE *above* the proxy group average and higher than the average for integrated electric utilities. As discussed in my Direct Testimony, TEP has higher risk associated with its generation portfolio compared to the companies in the proxy group, and also has above average regulatory risk in Arizona.[24]

Q. Mr. Parcell summarizes gas and electric utility authorized returns from 2012 to 2015 in his testimony.[25] Does this provide a reasonable benchmark for TEP's authorized return?

A. No, it does not. Although I generally agree with Mr. Parcell's figures for electric and gas utility rate case averages since 2012, he has not attempted to distinguish between vertically integrated electric utilities and electric distribution utilities. Vertically integrated utilities have much more risk than pure transmission and distribution ("T&D") utilities. The risks associated with owning generation assets include market risk, cost recovery risk, and regulatory risk associated with market forces, unplanned outages and maintenance and new environmental requirements. As shown in Table 3, authorized returns for vertically-integrated electric utilities have averaged between 25 and 60 basis points higher than returns authorized for T&D companies from 2012-2016. Mr. Parcell's recommendation does not reflect the additional risk of owning generation assets.

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24 Direct Testimony of Ann E. Bulkley, at 41-49.
25 Direct Testimony of David C. Parcell, at 14.

Table 3: Authorized ROEs for State Jurisdictional Electric Utility Operations[26]

Year	All Electric	Distribution	Vertically Integrated	Difference
2012	10.02%	9.75%	10.10%	0.36%
2013	9.82%	9.37%	9.95%	0.58%
2014	9.76%	9.49%	9.94%	0.45%
2015	9.60%	9.17%	9.75%	0.58%
2016	9.52%	9.39%	9.65%	0.26%

Q. Please describe the differences in your proxy group from that used by Mr. Parcell.

A. While there are many proxy group differences, the screening criteria used by Mr. Parcell and me are similar in many respects and result in an overlap of seven companies in our respective proxy groups (Allete, Great Plains Energy, IDACORP, Otter Tail Corp, Portland General Electric Corp, PNM Resources and Westar). There are five companies that I have included in my proxy group that Mr. Parcell has excluded; four of these (American Electric Power, Duke Energy Corp, Eversource Energy and Pinnacle West Capital Corp) were excluded for exceeding Mr. Parcell's $5 billion market capitalization threshold, and one company (Empire District Electric) was removed as it had announced a major acquisition subsequent to my proxy group selection. Three companies in Mr. Parcell's group were excluded from my proxy group; two of these companies (Avista and Northwestern Corp) do not meet my screening criterion requiring at least 90 percent of total regulated operating income from regulated electric operations, and El Paso did not have sufficient dividend payment history. Mr. Parcell has provided evidence using both his and my proxy groups. I conclude that the proxy group one chooses has no material bearing on his results.

[26] Source: SNL Financial. The number of authorized ROEs in 2016 is very limited, with only four decided cases included in this data set. Therefore, the 2016 results should be considered with caution.

1 **A. Constant Growth DCF Model**

2 **Q. Please summarize Mr. Parcell's Constant Growth DCF analyses.**

3 A. Mr. Parcell performs a Constant Growth DCF analysis with several indicators of
4 expected dividend growth, including:
5 1) historical earnings retention growth for years 2011-2015 (five-year average);
6 2) five-year average historic growth in earnings per share ("EPS"), dividends per share
7 ("DPS") and book value per share ("BVPS");
8 3) projections of earnings retention growth for 2016, 2017, and 2019-2021 (Value Line);
9 4) projections of EPS, DPS, and BVPS (Value Line) for years 2012-2014 to 2019-2021;
10 and
11 5) five-year projections of EPS growth (per First Call).
12
13 Mr. Parcell calculated mean and median returns for each individual growth rate, as well
14 as an ROE for the average of all growth rates. Mr. Parcell's Constant Growth DCF
15 analysis yielded mean and median ROE results of 8.0 percent, and produced a mean ROE
16 estimate ranging from 6.9 percent (historic and prospective earnings retention growth
17 rates) to 9.2 percent (5 year projected First Call EPS growth). All of these ROE
18 estimates are below any authorized ROE for a vertically-integrated electric utility in the
19 last 25 years.
20
21 **Q. Do you agree with Mr. Parcell that historical measures of growth are relevant to a**
22 **forward-looking evaluation of the Company's ROE?**

23 A. No, I do not. Mr. Parcell states that because of the "vast majority of historical
24 information available to investors, it is neither realistic nor logical to maintain that

investors only consider projected (estimated) data for a single statistic (EPS) to the exclusion of historic (actual) data and other statistics (historic and estimated)."[27] I disagree for two reasons. First, the Constant Growth DCF model is a forward-looking model that evaluates investors' required returns based on future cash flows. As such, the appropriate measure of growth is investors' expectations, not historical results. Historical growth rates are not relevant because past growth may not reflect future growth potential. Second, securities' analysts forecasted growth rates incorporate historical performance to the extent the analysts believe it is likely to continue. Additional consideration of historical growth rates provides no meaningful incremental information regarding the proxy companies' future growth potential and places unwarranted weight on historical events.

Q. Does Mr. Parcell disagree with the earnings growth estimates in your Constant Growth DCF model?

A. Yes, Mr. Parcell suggests that my recommendation is biased upward in a manner that inflates the return recommendation. He states that although I have included three measures of earnings growth in my Constant Growth DCF analyses, in reality all three focus on analysts' projections of earnings growth and exclude everything else.[28]

Q. What is your response?

A. As indicated in my Direct Testimony, dividend growth can only be sustained by earnings growth.[29] Earnings are the fundamental determinant of a company's ability to pay dividends. Further, both dividends and book value per share may be directly affected by short run management decisions. As a result, dividend growth rates and book value

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27 Direct Testimony of David C. Parcell, at 36-37.
28 Direct Testimony of David C. Parcell, at 36.
29 Direct Testimony of Ann E. Bulkley, at 26.

growth rates may not accurately reflect a company's long-term growth. In contrast, earnings growth rates are not affected by short run cash management decisions and are the only forward-looking growth rates available on a consensus basis.

While Mr. Parcell criticizes my use of EPS growth projections as the only measure of growth, it is in effect the only growth rate that he relies on in establishing his final DCF result of 9.2 percent. All other growth rates that he reviews produce returns that are at least 30 basis points below the lowest authorized ROE for any integrated electric utility from 2012-2016. Despite his criticism of analyst EPS growth rates, Mr. Parcell believes that the highest value in his analysis, which is based on analyst estimates of EPS growth, represents the current DCF-derived ROE for the proxy group.

Q. Do you agree with Mr. Parcell that "analysts still have a positive earnings growth bias"?[30]

A. No, I do not. Mr. Parcell references a McKinsey study and an SEC Investor Alert to support his claim of analyst bias; however, the evidence on the topic is far from clear and there are many conflicting opinions. A 2010 article in Financial Analysts Journal, for example, found that analyst forecast bias has significantly declined or disappeared entirely since the Global Settlement:

> Introduced in 2002, the Global Settlement and related regulations had an even bigger impact than Reg FD on analyst behavior. After the Global Settlement, the mean forecast bias declined significantly, whereas the median forecast bias essentially disappeared. Although disentangling the impact of the Global Settlement from that or related rules and regulations aimed at mitigating analysts' conflicts of interest is impossible, forecast bias clearly declined around the time the Global Settlement was announced. These results suggest that the

[30] Direct Testimony of David C. Parcell, at 37.

> recent efforts of regulators have helped neutralize analysts' conflicts of interest.[31]

Further, the Global Analysts Research Settlement of 2003 (the "Global Settlement") served to remove all incentives for bias in the financial industry. Specifically, the Global Settlement required financial institutions to insulate investment banking from analysis, prohibited analysts from participating in "road shows," and required the settling financial institutions to fund independent third-party research. In addition, analysts covering the common stock of the proxy companies must certify that their analyses and recommendations are not related, either directly or indirectly, to their compensation.

Q. Have other regulators offered an opinion on this issue?

A. Yes. The FERC has specifically addressed the concern about analyst growth rate forecasts in its March 2015 Order on Rehearing, Opinion 531-B, where it reaffirmed its rejection of the argument that analyst growth rates should not be used in the DCF analysis, because the analysts making those projections allegedly are overly optimistic in their projections.[32] The Commission also noted that the appropriate dividend growth rate to include in a DCF analysis is the growth rate expected by the market. While the market may be wrong in its expectations as reflected in the IBES growth projections, the cost of common equity to a regulated enterprise depends upon what the market expects, not upon precisely what is actually going to happen.[33]

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31 Armen Hovakimian and Ekkachai Saenyasiri, *Conflicts of Interest and Analyst Behavior: Evidence from Recent Changes in Regulation*, Financial Analysts Journal, Volume 66, Number 4, July/August 2010 at 195. Please note that this appears to be the published version of the working paper cited by Mr. Parcell.

32 FERC Order on Rehearing, Opinion No. 531-B (March 3, 2015) at para 71.

33 *Ibid.*

Q. Do you agree with Mr. Parcell's "retention growth" DCF analysis?

A. No, I do not. The underlying premise of the "retention growth" calculation is that future earnings will increase as the retention ratio (*i.e.*, the portion of earnings not paid out in dividends) increases. There are, however, several reasons why that may not be the case. Management decisions to conserve cash for capital investments, to manage the dividend payout for the purpose of minimizing future dividend reductions, or to signal future earnings prospects can and do influence dividend payout (and therefore earnings retention) decisions in the near-term.

Q. Is there academic research that supports your position?

A. Yes. In 2006, two articles appeared in Financial Analysts Journal, which addressed the theory that high dividend payouts (*i.e.*, low retention ratios) are associated with low future earnings growth.[34] Both of those articles cite a 2003 study by Arnott and Asness[35] who found that, over the course of 130 years of data, future earnings growth is associated with high, rather than low payout ratios.[36] In essence, the findings of all three studies are that there is a negative, not a positive relationship between earnings growth rates and payout ratios. As such, I disagree with Mr. Parcell's use of the retention growth model.

Q. Do you have other concerns regarding Mr. Parcell's retention growth rates?

A. Yes. Mr. Parcell's retention growth rates are too low to be credible. In addition, these growth rates require an estimate of the earned return on common equity and are therefore

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[34] Ping Zhou, William Ruland, *Dividend Payout and Future Earnings Growth*, Financial Analysts Journal, Vol. 62, No. 3, 2006. *See* also Owain ap Gwilym, James Seaton, Karina Suddason, Stephen Thomas, *International Evidence on the Payout Ratio, Earnings, Dividends and Returns*, Financial Analysts Journal, Vol. 62, No. 1, 2006.

[35] Robert Arnott, Clifford Asness, *Surprise: Higher Dividends = Higher Earnings Growth*, Financial Analysts Journal, Vol. 59, No. 1, January/February 2003.

[36] Since the payout ratio is the inverse of the retention ratio, the authors found that future earnings growth is negatively related to the retention ratio.

somewhat circular. By adopting Value Line's earned ROE estimates, Mr. Parcell has effectively pre-supposed the return on common equity projected by Value Line for the proxy group companies. As shown on Exhibit DCP-1, the average Value Line earned ROE estimates for the companies in Mr. Parcell's proxy group from 2011-2015 ranged from 8.3 to 8.9 percent,[37] yet for the same period he calculates a mean DCF result, using historical retention growth rates covering the same period, of 6.9 percent, a difference of 140 to 200 basis points. Similarly, his prospective retention growth rate produces a DCF result of 6.9 percent, but the implied ROEs (upon which those growth rates were calculated) actually ranged from 8.4 to 9.2 percent,[38] a difference of 150 to 230 basis points. These retention growth DCF results are unreasonably below the return on equity authorized for any electric utility that I am aware of. In fact, Mr. Parcell did not appear to consider these results reasonable based on his DCF estimate of 9.2 percent.

Q. Has the FERC recently abandoned the use of earnings retention growth rates in its electric transmission ROE methodology?

A. Yes. In Opinion No. 531, the FERC changed its approach on the DCF methodology to be applied in public utility rate cases.[39] In summary, the FERC adopted the same two-step DCF methodology it has employed in gas and oil pipeline rate proceedings since the mid-1990s, in place of the one-step methodology previously used. The FERC's two-stage DCF approach does not rely on a retention growth calculation, and instead incorporates a long-term growth projection equal to GDP. The FERC justified its change on several grounds, but as is relevant in this proceeding, it determined that both a short-term and long-term growth rate should be incorporated into the DCF calculation for public utilities. The FERC explained that its previous approach for electric utilities, using a one-stage

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37 *See* DCP-1, Schedule 10, p. 1 of 2.
38 *Ibid.*
39 Opinion No. 531 147 FERC ¶ 61,234 (June 19, 2014).

DCF model, based on a short-term retention growth rate, was established at a time when electric utilities were just beginning the process of restructuring and that in the Commission's view investors would place limited weight on long-term growth projections. However, the FERC in revisiting its approach for electric utilities, finds that there is no longer reason to distinguish between gas pipelines and electric utilities in its DCF methodologies, and it has chosen to align its approach. When intervenors challenged the use of analyst earnings growth rates as the short term growth rate as opposed to a retention growth rate, the FERC responded as follows:

> We also reject Petitioners' argument that the Commission should have used the "br+sv" growth rate as the short-term growth rate in the two-step DCF methodology. While the "br+sv" growth formula relies on short-term Value Line projections of five years or less for the various inputs to the formula, it seeks to estimate a company's "sustainable growth rate."
>
> For that reason, although the Commission has stated that the formula "only produces a projection of short-term growth, similar to the IBES projections," the Commission finds the formula unreasonable for use as the short-term growth projection in the two-step DCF methodology. By seeking to estimate a "sustainable growth rate," the "br+sv" growth formula also contains some elements of a long-term growth projection, in addition to a short-term growth projection, and thus is inappropriate for use as a purely short-term growth projection in a two-step DCF methodology.
>
> The Commission adopted the two-step DCF methodology because, among other reasons, its incorporation of a long-term growth projection in the cost of equity calculation would have the effect of ascribing sustainable long-term growth to all members of a proxy group. Thus, the Commission's adoption of the two-step DCF methodology accomplishes what the use of the "br+sv" formula was intended to accomplish.[40]

[40] Opinion No. 531-B, 147 FERC ¶ 61,234 Order on Rehearing (March 3, 2015) at para.77.

B. Multi-Stage DCF Analysis

Q. Did Mr. Parcell criticize your multi-stage DCF analysis?

A. Yes. Mr. Parcell criticizes my use of analyst EPS projections for the short-term growth rate in the Multi-Stage model filed in my Direct Testimony. I have previously addressed Mr. Parcell's concerns with the use of analyst growth rates. Mr. Parcell also takes exception to the long-term GDP growth rate used in the final stage of my Multi-Stage DCF model, claiming that the use of historical data for my GDP growth rate is inconsistent with projected growth rates used elsewhere in my DCF analyses.

Q. What is your response to Mr. Parcell's criticisms of your Multi-Stage DCF analysis?

A. The long-term growth rate used in my Multi-Stage DCF analysis is consistent with industry practice. For example, as Morningstar explains, it is appropriate to use historical real growth in GDP combined with projected inflation to calculate nominal GDP growth:

> Growth in real GDP (with only a few exceptions) has been reasonably stable over time; therefore, its historical performance is a good estimate of expected long-term future performance. By combining the inflation estimate with the real growth rate estimate, a long-term estimate of nominal growth is formed…[41]

With regard to the time period used to compute average historical growth in real GDP, Morningstar writes:

> The 87-year period starting with 1926 is representative of what can happen: it includes high and low returns, volatile and quiet markets, war and peace, inflation and deflation, and prosperity and depression. Restricting attention to a shorter historical period underestimates the amount of change that could occur in a long future period. Finally, because historical event-types (not specific events) tend to repeat themselves, long-run capital market return studies can reveal a great

[41] Ibbotson and Associates, Stocks, Bonds, Bills and Inflation, 1926-2012, 2013 Valuation Yearbook, at 52.

deal about the future. Investors probably expect "unusual" events to occur from time to time, and their return expectations reflect this.[42]

Q. Mr. Parcell states that economists and various government agencies are forecasting lower GDP growth rates.[43] What is your response?

A. Nominal GDP growth rates of 4.40 percent to 4.60 percent, as published in the reports cited by Mr. Parcell, are well below the average nominal GDP growth rate in the U.S. since 1926. By comparison, my historical GDP growth rate of 5.40 percent is based on a projected inflation rate of 2.09 percent (based on three sources), and actual historical growth in real GDP of 3.25 percent from 1929-2015.[44]

Moreover, as discussed in my Direct Testimony, there has been a tendency to under-estimate GDP growth in the decade after severe economic events.[45] The financial crisis and recession that began in 2007 were qualitatively different from most other U.S. economic downturns, which were followed by a rapid return to pre-recession overall output growth levels. The current U.S. economic growth situation is similar to that following the two most severe U.S. economic events in the last century (*i.e.*, the 1929 stock market crash and the 1973 oil shock).

Q. What is your conclusion regarding the appropriate GDP growth rate for the Multi-Stage DCF analysis?

A. In my view, current estimates of real GDP growth are understated relative to the long-term average because forecasters are placing too much weight on recent economic weakness. For that reason, I believe it is reasonable to use historical long-term GDP

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42 *Ibid.*, at 59.
43 Direct Testimony of David C. Parcell, at 39.
44 *See* Exhibit AEB-3 filed with my Direct Testimony.
45 Direct Testimony of Ann E. Bulkley, at 29.

growth as the terminal growth rate in the Multi-Stage DCF model. However, the Multi-Stage DCF model does not directly reflect the substantial increase in interest rates that is projected over the next five years, as borrowing costs increase from the artificially low levels of the recent past.

C. CAPM Analysis

Q. Please summarize Mr. Parcell's CAPM results and explain how he uses that analysis.

A. Mr. Parcell's CAPM analysis produces mean results of 6.70 percent for the Parcell Proxy Group and 6.50 percent for the Bulkley Proxy Group. These results are based on a risk free rate of 2.23 percent, Value Line betas ranging from 0.50 to 0.85, and a market risk premium ("MRP") of 5.75 percent. Although Mr. Parcell testifies that his CAPM results should be considered as one factor in determining the cost of equity for TEP, he ultimately relies on the results set by his Constant Growth DCF model and his Comparable Earnings Analysis for his recommended range of 9.2 percent to 9.5 percent.[46] The results of Mr. Parcell's CAPM analysis are well below the authorized ROE for any U.S. electric utility company in the past 25 years.[47]

Q. What are the areas in which you disagree with Mr. Parcell's CAPM analysis?

A. I have two areas of concern with the inputs and assumptions that Mr. Parcell has relied on to derive his CAPM results. First, I do not believe that Mr. Parcell's risk free rate of 2.23 percent adequately considers projected increases in Treasury bond yields that are expected over the period that TEP's rates are likely to be in effect. Second, I disagree with Mr. Parcell's use of a MRP of 5.75 percent.

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46 Direct Testimony of David C. Parcell, at 33.

47 Source: SNL Regulatory Research Associates.

Q. Please explain your concern with the risk free rate that Mr. Parcell has used in his CAPM analysis.

A. Mr. Parcell has used a current three-month average of the 20-year Treasury bond yield for his risk-free rate in conjunction with a long-term historical average MRP. My primary concern is that when interest rates are anomalously low, as they are today, it is important to either use a normalized interest rate that is more characteristic of the long term average, or a current interest rate in conjunction with a forward-looking MRP that reflects the current interest rate environment and the inverse relationship of the market risk premium to interest rates.

The inputs and assumptions used in the ROE analysis should reflect the forward-looking cost of equity. Mr. Parcell agrees that the cost of capital is forward looking.[48] As discussed in Section III of my Rebuttal Testimony, leading economists surveyed by Blue Chip are expecting higher interest rates over the next five years. This is a very important consideration for equity investors as they assess their return requirements. Mr. Parcell makes no attempt to normalize the current anomalously low interest rates and yet pairs them with the long term average market risk premium, which is based on much higher interest rates. Mr. Parcell's risk free rate of 2.23 percent does not adequately take into consideration the effect of the market's expectation for higher interest rates on the cost of equity for TEP. For that reason, I believe that Mr. Parcell's CAPM results are significantly understated.

[48] Staff Response to TEP Data Request 2.14(B)("Mr. Parcell considers the cost of capital to be forward looking.").

Q. Mr. Parcell states that it is "not proper to use projected interest rates as the risk-free rate" and that the current yield is the proper rate because it is "known and measurable and reflects investor's collective assessment of all capital market conditions." Do you agree?

A. No, I do not. First, I disagree that current interest rates reflect investors' collective assessment of all capital market conditions. As I have stated previously in this testimony, current yields on U.S. Treasury securities are being driven by the Federal Reserve's monetary policy, not by typical bond market participants; and today's low interest rates are not reliable indicators of investment risk or the cost of capital in equity markets over the period that the rates in this case will be in effect. It is common practice for analysts to use normalized interest rates, as I have done by using a forecast bond yield, particularly in anomalous market conditions, because forecasted bond yields provide a more reliable indication of investment risk and the cost of capital over the expected rate period.

Q. What MRP does Mr. Parcell use in his CAPM analysis?

A. Mr. Parcell estimates the MRP as being in the range of 4.40 percent to 6.85 percent. From within that range, he chooses an MRP of 5.75 percent.[49]

Q. What is the basis for Mr. Parcell's MRP estimate?

A. Mr. Parcell considered several alternate measures of the equity risk premium. On Schedule 8, Mr. Parcell calculates the historical ROE of the S&P 500 for each year from 1978 to 2014 by dividing earnings per share by average book value per share for each year. He arrives at the annual risk premium by subtracting the total return on the 20-year Treasury bond. The average of all the yearly risk premiums is 6.85 percent. As an

[49] Direct Testimony of David C. Parcell, at 28.

alternative measure, he considers total returns for the S&P 500, less the total return of the 20-year Treasury as tabulated by Morningstar, using both arithmetic and geometric averages for the period from 1926-2014. That analysis resulted in risk premiums of 6.0 percent (arithmetic) and 4.4 percent (geometric).

Q. Why do you disagree with Mr. Parcell's estimate of the MRP?

A. First, the MRP that Mr. Parcell estimates is an annual historical value that is not necessarily reflective of current or projected market conditions. Second, the MRP should be a market-based input to the CAPM, entirely subject to market forces. Mr. Parcell's calculation of the annual return on book equity for the S&P 500 removes the market assessment from the model. Mr. Parcell has substituted the accounting book value for the market valuation embedded in stock returns. By calculating the annual return on book equity rather than the return on share price, he is removing the objectivity inherent in a market model and substituting accounting data and all of the idiosyncrasies associated with that data into his analysis. The CAPM is a market model, and its inputs should be derived from the equilibrium of market forces, not accounting cost and earnings information.

Q. What are your other concerns with Mr. Parcell's MRP estimate?

A. Aside from the fact that Mr. Parcell relies entirely on historical data for his MRP and provides no forward-looking risk premium estimate, his averaging of historical MRPs based on geometric means and arithmetic means is without basis. He states that, "a combination of arithmetic and geometric means is appropriate since investors have access

to both types of means presumably, both types are reflected in investment decisions and thus stock prices and the ROE."[50] I disagree.

Geometric returns serve a specific purpose, as do arithmetic returns. To simply average the two, because they are both published and available to investors is completely without basis. The only appropriate mean for this purpose is the arithmetic mean. The geometric mean is the compound rate that equates a beginning value to its ending value. It is used to determine the exact rate of compounded return between a specific starting and ending point. The arithmetic mean is the simple average of single period rates of return and best approximates the uncertainty associated with returns from year to year. The important distinction between the two methods is that the arithmetic mean assumes that each periodic return is an independent observation and, therefore, incorporates uncertainty into the calculation of the long-term average. By contrast, the geometric mean does not incorporate the same degree of uncertainty because it assumes that returns remain constant from year to year. In his review of literature on the topic, Cooper noted the following rationale for using the arithmetic mean:

> Note that the arithmetic mean, not the geometric mean is the relevant value for this purpose. The quantity desired is the rate of return that investors expect over the next year for the random annual rate of return on the market. The arithmetic mean, or simple average, is the unbiased measure of the expected value of repeated observations of a random variable, not the geometric mean....[The] geometric mean underestimates the expected annual rate of return.[51]

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50 Direct Testimony of David C. Parcell, at 27-28.

51 Ian Cooper, *Arithmetic versus geometric mean estimators: Setting discount rates for capital budgeting*, European Financial Management 2.2, (1996): 158.

Q. You noted earlier that Mr. Parcell computed his MRP estimates using the "total return" on the 20-year government bond yield, not the "income return." Why is it not appropriate to use the total return on government bonds to derive the MRP?

A. According to Morningstar, the historical MRP is appropriately calculated by subtracting the *income only* portion of the government bond return from the total return on large company stocks:

> Another point to keep in mind when calculating the equity risk premium is that the income return on the appropriate-horizon Treasury security, rather than the total return, is used in the calculation. The total return is comprised of three return components: the income return, the capital appreciation return, and the reinvestment return...The income return is thus used in the estimation of the equity risk premium because it represents the truly riskless portion of the return.[52]

By subtracting the total return on government bonds from the total return on large company stocks, Mr. Parcell has understated the historical MRP by approximately 100 basis points (using the arithmetic mean).[53] Based on Mr. Parcell's average Beta coefficient of 0.78, the effect on his mean CAPM estimate is approximately 78 basis points. Even with that correction, using a historical MRP renders results that are far too low to be reasonable estimates of TEP's cost of equity.

Q. Mr. Parcell contends that your MRPs are overstated. What is your response?

A. Mr. Parcell presumes that my forward-looking MRP is over-stated because it exceeds the average long term MRP from 1926 to present. Mr. Parcell testifies: "Ms. Bu[l]kley offered no evidence or rationale to explain why investors would expect such a large increase in risk premiums over historic levels. Again, Ms. Bu[l]kley chooses data that

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[52] Morningstar, Ibbotson SBBI 2012 Valuation Yearbook, Market Results for Stocks, Bonds, Bills, and Inflation 1926-2011, at 55.

[53] Morningstar SBBI Presentation, Morningstar Stocks, Bonds, Bills, and Inflation 1926 – 2015, at 6.

produce higher and excessive results."[54] One needs to look no further than Mr. Parcell's own Schedule 8, where he shows, by his own estimation that the MRP increased from 7.94 percent prior to the financial market collapse in 2007 to 10.85 percent in 2014, the last year of his analysis. Mr. Parcell's analysis demonstrates that investors expect higher risk premiums over historical levels. In fact, Mr. Parcell's recent estimates of the MRP are higher than those used in my analysis.

Q. Are there other regulatory agencies that have offered opinions on a forward-looking CAPM?

A. Yes. In Opinion 531-B the FERC specifically addressed the assumptions used in a projected CAPM analysis. The FERC concluded that estimates of the MRP using the same methodology that was used in my Direct Testimony were appropriate. Specifically, the FERC stated:

> ...As an initial matter, we reject EMCOS's argument that the NETOs' CAPM analysis is flawed because it used a DCF study to determine the market risk premium. As explained above, using a DCF study is the standard method of calculating the market risk premium in a forward-looking CAPM analysis. We are, therefore, unpersuaded that the use of a DCF study renders the NETOs' CAPM analysis deficient. We also disagree with Petitioners' argument that the NETOs' CAPM analysis relied on an overly optimistic growth rate input in determining the market risk premium. The growth rate in the NETOs' CAPM analysis is based on IBES data, which the Commission has long relied upon as a reliable source of growth rate data.[55]

Q. What are your conclusions regarding Mr. Parcell's CAPM analysis?

A. Mr. Parcell's inputs to the CAPM analysis are based on historical data rather than forward-looking investor expectations. Under the current interest rate environment, the

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54 Direct Testimony of David C. Parcell, at 42 [corrected spelling of Bulkley].

55 Opinion No. 531-B, 147 FERC ¶ 61,234 Order on Rehearing (March 3, 2015) at para 110.

CAPM does not produce reliable results without making adjustments to certain inputs and assumptions. Mr. Parcell attributes his lower CAPM results to lower interest rates and believes that investors expect lower risk premiums than in prior years as a result of lower equity market returns and a perceived decline in investor expectations of equity returns and risk premiums.[56] Mr. Parcell fails to acknowledge the well-established inverse relationship between the market risk premium and interest rates. Given the current low yields on Treasury bonds, and the inverse relationship between interest rates and the MRP, the MRP should be higher than the historical average, not lower. This is demonstrated in Mr. Parcell's annual estimate of the MRP.[57]

The average historical income only return on long-term government bonds that is used to calculate the historical MRP is 5.00 percent, while the current 30-day average risk free rate on long-term government bonds is approximately 2.65 percent. The historical MRP as reported by Ibbotson and Associates is 7.0 percent through 2015. Because interest rates on long-term government bonds are well below the historical average of 5.00 percent, the inverse relationship between interest rates and the MRP implies that the forward-looking MRP should be higher than 7.0 percent. Consequently, Mr. Parcell's interest rate and MRP in his CAPM analysis are too low and provide no meaningful insight into the cost of equity for TEP. Furthermore, while Mr. Parcell is critical of the assumptions used in my CAPM analysis, his assumptions produce a mean of 6.7 percent for his proxy group – a result that is at least 260 basis points below the lowest authorized ROE for an electric utility, that I am aware of; and 265 basis points below his own ROE recommendation in this case. These results are so low that Mr. Parcell does not even use them in setting his recommended ROE.[58]

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56 Direct Testimony of David C. Parcell, at 33.

57 Direct Testimony of David C. Parcell, Schedule 8.

58 Direct Testimony of David C. Parcell, at 33, where he states, "*This range includes my DCF result (9.2 percent), and my CE result (9.5 percent)....*"

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2 **D. Comparable Earnings Analysis**

3 **Q. Please explain your concerns with Mr. Parcell's Comparable Earnings Analysis.**

4 A. Mr. Parcell provides a Comparable Earnings analysis that presents "realized returns" over
5 a period that is too long (as far back as 2002) to be relevant in this proceeding. Many of
6 the proxy companies would not have met my screening criteria during those historical
7 periods, particularly those that have had credit ratings below investment grade.
8 Furthermore, realized book returns are not a good proxy for the return that investors
9 expect going forward, especially realized book returns that date back over a decade and
10 include losses from non-electric operations. For example, according to Mr. Parcell's
11 Schedule 10, PNM Resources earned an ROE of 3.4 percent in 2007, 0.50 percent in
12 2008, and 3.10 percent in 2009. According to PNM's 10-K, these disappointing returns
13 were not attributable to ongoing utility operations, but rather impairment of goodwill,
14 trading losses in unregulated operations, high rates of customer defaults, and significant
15 regulatory disallowances. It makes little sense to incorporate such factors into a forward-
16 looking return estimate, particularly when these events occurred nearly a decade ago.
17 Similarly, low returns for Otter Tail between 2008 and 2011 appear to be entirely due to
18 losses in non-electric operations. It is not appropriate to bring historical accounting
19 returns into an exercise that is setting forward-looking ROE. Mr. Parcell's Comparable
20 Earnings analysis is a backward looking measure with no consideration of or relevance to
21 current market conditions. Alternatively, the authorized ROEs for the utility subsidiaries
22 of the proxy companies is more reflective of the regulated ROE that investors expect for
23 similar risk companies. Based on my analysis of the authorized returns of the utility
24 subsidiaries of the proxy companies, those authorized returns averaged 9.98 percent.
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E. Conclusions on Mr. Parcell's ROE Recommendation

Q. What is your conclusion regarding Mr. Parcell's ROE recommendation of 9.35 percent?

A. While I present several results in my testimony, I consider the effect of market conditions on certain models and weight the results accordingly. My recommended ROE is within the range established by the high end of the DCF analysis presented in my Direct Testimony as well as the low end of the range established by the results of the CAPM. In contrast, while Mr. Parcell criticizes the assumptions used in my analyses in support of his own methodologies, he discards nearly all of his own results. Specifically, Mr. Parcell offers extensive criticism of the assumptions used in my CAPM, offering instead his view on the appropriate specification of this model, then discards the results of that model.

With respect to the DCF model, Mr. Parcell spends pages criticizing my exclusive use of EPS growth rates, yet the only DCF result from the myriad of growth rates he uses in his DCF model is the one derived from EPS growth rates.

Mr. Parcell criticizes my use of forecasted interest rates in my regression risk premium analysis, claiming that resulting ROEs are too high, despite the fact that those ROEs are based solely on the historical relationship between interest rates and authorized returns. While Mr. Parcell criticizes the use of projected data in my various analyses, he relies on a Comparable Earnings methodology that produces returns, even on a projected basis, that are lower than the 9.5 percent ROE that he concludes is derived from this methodology.

F. Capital Structure

Q. Mr. Parcell rejects the adjustments TEP made to its test year capital structure and cost of debt. Is this appropriate?

A. I don't believe so. It is common practice for utilities to adjust historical test year figures for known and measurable differences. Utilities already are dealing with regulatory lag when using a historical test year, particularly in periods of significant capital investment. By disallowing adjustments for known and measureable differences, the utility's rates are based on a rate base that is obsolete by the time rates go into effect, in effect disallowing any recovery for those known and measurable differences. As I have shown in my Direct Testimony, TEP's proposed capital structure of 50.03 percent is well below the mean of the proxy group of 54 percent and toward the low end of the range of equity ratios for the proxy companies. Mr. Parcell reports in his testimony that AUS Utility Reports indicate that the average gas and electric utility equity ratio in 2015 is 47 percent. However, this is the average equity ratio for utility holding companies and is not reflective of the utility operating companies' authorized equity ratios. Given TEP's significant risk profile, I would expect it to require more equity in its capital structure than the companies in its proxy group. Accordingly, TEP's proposed capital structure should be accepted.

G. Fair Value Rate of Return

Q. Please summarize Mr. Parcell's proposed return on the FVROR and Fair Value Increment.

A. Mr. Parcell recommends a FVROR of between 0.00 percent and 1.42 percent. In support of his position that the return on the FVRB increment should be zero, Mr. Parcell states that "[s]ince the increment between the FVRB and OCRB is not financed with investor-supplied funds, it is logical and appropriate, from a financial standpoint, to assume that

this increment has no financing costs".[59] While Mr. Parcell provides this recommendation, he also provides a calculation of the return on the FV increment. In that calculation, Mr. Parcell estimates the real risk-free rate and the difference between the nominal risk-free rate and inflation, which results in a return on the fair value increment of 1.42 percent. That is consistent with the return that is proposed in my Direct Testimony. Mr. Parcell's third calculation of the return on the fair value increment applies 50 percent of the real risk-free rate, or 0.70 percent, to the fair value increment.[60] The resulting FVROR resulting from this final method is 5.00 percent.

Q. Do you agree with Mr. Parcell's recommendation?

A. While I generally agree that the return on the Fair Value increment should be based on the real risk-free rate, I do not agree with the approach Mr. Parcell has used to calculate that return. Mr. Parcell relies on projected Treasury bond yields for a very short-term, ending in the second quarter of 2017. With the expectation that interest rates will increase, it would be reasonable to rely on a longer projection to reflect the period that these rates may be in effect. As shown in my Direct Testimony, the average projected return on 30-year Treasury bonds for 2017-2021 was 110 basis points higher than the yield Mr. Parcell relied on.

Q. How would the return on the Fair Value Increment change if you made these modifications to Mr. Parcell's analysis?

A. Relying on an expected nominal risk-free rate of 4.80 percent and Mr. Parcell's inflation factor of 2.3 percent would result in real risk-free rate of 2.50 percent and a return on the

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59 Direct Testimony of David C. Parcell, at 45.

60 *Ibid.*, at 48-49.

fair value increment of 1.25 percent, which is 55 basis points higher than Mr. Parcell's recommendation.

Q. What is the effect of this change on the FVROR?

A. While I disagree with Mr. Parcell's recommended ROE of 9.35 percent, for the purposes of illustration, maintaining that cost rate and adjusting the return on the fair value increment to reflect a projected real risk-free rate, the FVROR would be 5.16 percent. Assuming an ROE of 10.00 percent and a return on the fair value increment of 1.25 percent, the resulting FVROR would be 5.57 percent.

V. RESPONSE TO RUCO WITNESS MEASE

Q. Please summarize Mr. Mease's analyses and recommendations.

A. Based on his analyses, Mr. Mease develops a range of ROE results from 7.91 percent to 9.65 percent and recommends an ROE for TEP of 9.20 percent.[61] The high and low results of Mr. Mease's Constant Growth DCF analysis form the upper and lower boundaries of his range of results. His CAPM analyses (yielding a mean result of 7.97 percent) and his Comparable Earnings analysis (yielding a range from 8.50 percent to 9.30 percent) fall within his range. Mr. Mease indicates that his point estimate of 9.20 percent is at the high side of the range of results derived from his DCF, CAPM and Comparable Earnings ("CE") analyses.[62] Mr. Mease testifies that the economy is recovering from recession more slowly than expected and that expected investment returns have declined. He states that given the economic uncertainty going forward, interest rates will remain at or near current levels for the next several years.[63] Mr. Mease

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61 Direct Testimony of Robert B. Mease, at 27.
62 *Ibid.*, at 17.
63 *Ibid.*, at 12-13.

supports the Company's proposed capital structure of 50.03 percent common equity and 49.97 percent long-term debt. He calculates the weighted average cost of capital of 7.30 percent. Further, Mr. Mease recommends a FVROR for TEP of 5.20 percent, which he derives by subtracting an inflation rate of 1.56 percent from his inflation adjusted weighted average cost of capital of 6.76 percent.

Q. Is Mr. Mease's ROE recommendation of 9.20 percent fair and reasonable for TEP?

A. No, Mr. Mease's ROE recommendation of 9.20 percent is 80 basis points below TEP's currently authorized ROE and well below returns available from other comparable-risk investments. Mr. Mease's discussion of economic and capital market conditions does not reflect the reality of higher credit spreads, or prospects for higher interest rates, or the volatility that has characterized the broader equity market in recent months. As a result, Mr. Mease's recommendation does not reflect the current and prospective market conditions that TEP will experience during the period in which rates will be in effect. Finally, Mr. Mease has failed to take into consideration additional business and regulatory risks which differentiate TEP from the proxy group companies.

Q. Mr. Mease notes that rate filings by electric utilities in 2015 were the fewest in seven years and the average awarded ROE was the lowest in three decades. Does this put his recommendation into perspective?

A. Although it is true that authorized ROEs have trended down with interest rates over the past decade and are near the lowest level in three decades, no authorized return for vertically-integrated utilities has been authorized as low as Mr. Mease's recommendation of 9.20 percent for TEP. The EEI Report Mr. Mease cites in his testimony indicates that the mean authorized return for electric utilities is 9.85 percent, or 65 basis points higher than his recommendation. That average ROE includes both T&D and vertically

integrated companies. TEP's risk related to operating an extensive generation portfolio should result in an ROE above the mean for that sample group.

Q. What are your principal areas of disagreement with Mr. Mease?

A. I disagree with the following aspects of Mr. Mease's analyses: (1) his primary reliance on a Constant Growth DCF model; (2) his use of projected dividend growth rates in the Constant Growth DCF model; (3) his application of the CAPM and the reasonableness of his CAPM results; (4) his failure to take into consideration the higher business and regulatory risks to which TEP is exposed relative to the proxy group companies; and (5) his FVROR recommendation and the method used to derive that recommendation.

A. Application of the Constant Growth DCF Model

Q. What growth rate does Mr. Mease rely on in his Constant Growth DCF analysis?

A. Mr. Mease states that dividend growth can be measured using the product of a company's retention ratio and its return on book equity.[64] This is the sustainable growth rate commonly expressed as the "b" x "r" growth rate. However, in Exhibit RBM-5, Mr. Mease's analysis relies on both projected dividend growth rates, as reported by Value Line, and analysts' projected earnings growth rates as, reported by Yahoo! Finance, not on sustainable growth, as his testimony implies.

Q. Do you agree with the growth rates that Mr. Mease relies on in his DCF analysis?

A. Not entirely. Mr. Mease relies on an average of projected dividend per share growth and earnings per share growth rates to estimate the growth rate in the DCF model. Estimates

[64] *Ibid.*, at 9.

of earnings growth are more indicative of long-term investor expectations than are dividend or book value growth estimates because earnings growth is least influenced by capital allocation decisions that companies may make in response to near-term changes in the business environment. Furthermore, earnings are the fundamental driver of a company's ability to pay dividends. As noted by Brigham and Houston:

> Growth in dividends occurs primarily as a result of growth in earnings per share (EPS). Earnings growth, in turn, results from a number of factors, including (1) inflation, (2) the amount of earnings the company retains and invests, and (3) the rate of return the company earns on its equity (ROE).[65]

In the analysis presented in my Direct Testimony, the growth rate used in the Constant Growth DCF model is a projected earnings per share growth rate.

Q. Have you reviewed the Potomac Electric Power decision that Mr. Mease cites as support for relying on the DCF model?

A. Yes, I have. While the commission in that case did rely on the DCF model, there are other important factors to be noted from this decision. First, the commission indicated that while it has a preference for the DCF model, it does not preclude parties from filing other approaches and most importantly, the commission considered the entire record, "which may include actions taken by other commissions and recent changes in the law."[66] Furthermore, the commission set the upper bound of the ROE at the high end of the range of the Constant Growth DCF results, calculated based on the high earnings per share growth rates; this is similar to the calculation that Mr. Mease performed that resulted in an ROE of 9.65 percent. Finally, it is important to note that the ROE that was established by that commission in 2014 for Potomac Electric Power (a lower-risk transmission and

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65 Eugene F. Brigham and Joel F. Houston, *Fundamentals of Financial Management*, at 317 (Concise Fourth Edition, Thomson South-Western).

66 Public Service Commission of the District of Columbia, Order and Opinion No. 17424, March 26, 2014, p. 102-103.

distribution only utility) was 9.50 percent, or 30 basis points higher than the ROE recommended by Mr. Mease.

Q. Has the FERC provided a rationale for setting the ROE at the upper end of the range of reasonable returns?

A. Yes, it has. In FERC Opinion No. 531-B, the FERC allowed a return for the NETOs that was midway between the median return and the high end of the range. The Commission found that, although it typically sets the base ROE for a group of utilities at the midpoint of the zone of reasonableness identified by the DCF methodology, a mechanical application of the DCF methodology with the use of the midpoint here would result in an ROE that does not satisfy the requirements of Hope and Bluefield. Therefore, the Commission explained that based on the record in this case, including the unusual capital market conditions, the base ROE for the NETOs should be set halfway between the midpoint of the zone of reasonableness and the top of the zone of reasonableness.

As a result of the anomalous capital market conditions reflected in the record, and their potential impact on the DCF model, the Commission found it necessary and reasonable to consider additional record evidence, including evidence of alternative benchmark methodologies and state commission-approved ROEs, to gain insight into the potential impacts of these unusual capital market conditions on the appropriateness of using the [midpoint of the zone of reasonableness identified by the DCF methodology].[67]

The Commission found the additional record evidence—specifically the NETOs' risk premium analysis, Capital Asset Pricing Model (CAPM) analysis, expected earnings analysis, and evidence of state commission-authorized ROEs—supported a finding that

[67] Opinion No. 531-B, 147 FERC ¶ 61,234 Order on Rehearing (March 3, 2015) at para. 36-37.

an upward adjustment from the midpoint was warranted. The FERC ruled that anomalous conditions warranted an ROE at the upper end of the reasonable range. As yields on Treasury bonds have continued to decline since the FERC issued Opinion 531-B, it is reasonable to believe that conditions in capital markets remain "anomalous," which would warrant a placement of ROE above the midpoint of the DCF results. As Mr. Mease's median DCF result is 8.56 percent and the mean high result is 12.26 percent, a midpoint ROE estimate would be 10.41 percent.

B. Application of Capital Asset Pricing Model

Q. Please summarize Mr. Mease's CAPM analysis and results.

A. Mr. Mease's CAPM analysis relies on what appears to be a historical MRP of 6.91 percent, the three-month average yield on 30-year Treasury bonds of 2.64 percent as the risk-free rate, and Value Line Betas for the proxy group ranging from 0.70 to 0.85.[68] That analysis produces an ROE estimate for TEP of 7.97 percent.[69]

Q. Please comment on the reasonableness of Mr. Mease's CAPM result.

A. Mr. Mease's CAPM result of 7.97 percent is entirely inconsistent with the returns required by equity investors for companies with commensurate risk, and is 203 basis points below TEP's currently authorized ROE. Furthermore, Mr. Mease's CAPM result has never been observed as an authorized ROE for any electric utility in at least the past 25 years.

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[68] Exhibit RBM-6.

[69] Direct Testimony of Robert B. Mease, at 25.

Q. Do you agree with Mr. Mease's use of only the three-month average yield on the 30-year Treasury security as the risk-free rate in his CAPM analysis?

A. No, I do not. As Mr. Mease notes, the Commission has stated that "the consideration of both historical and projected data is appropriate in evaluating the Cost of Equity".[70] Therefore, the use of only the three-month historical average yield of 2.64 percent as the risk-free rate is not reasonable, especially when considering investors' expectation for rising interest rates during the period when this return will be in effect. Furthermore, Mr. Mease fails to take into consideration the inverse relationship between interest rates and the MRP. That is, if current interest rates are approximately 250 basis points below historical levels, it is not appropriate to use the three-month average historical yield on 30-year Treasury securities as the risk-free rate in conjunction with the historical MRP. Furthermore, Mr. Mease's CAPM analysis does not consider the market's expectation for rising interest rates on the cost of equity. Projected yields on 30-year Treasury securities indicate that investors are expecting substantially higher interest rates and higher inflation over the next five years.

Q. Do you agree with the MRP of 6.91 percent that Mr. Mease has used in his CAPM analysis?

A. Mr. Mease does not provide a source for his MRP estimate; however, it is generally consistent with historical MRPs. What is clear is that it is not a forward-looking MRP, and in that case should only be used with a normalized risk-free rate that better reflects the risk-free return investors require and accordingly the cost of capital. As discussed in my response to Mr. Parcell, today's artificially low interest rates are not indicative of the true required return for investment in risk-free securities.

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[70] Direct Testimony of Robert B. Mease, at 29. See also Decision No. 75268.

Q. What are your conclusions regarding Mr. Mease's CAPM analysis?

A. Mr. Mease's inputs to the CAPM analysis are based on historical data rather than forward-looking investor expectations. Under the current interest rate environment, the CAPM does not produce reliable results without making adjustments to certain inputs and assumptions. Consequently, Mr. Mease's CAPM analysis provides no meaningful insight into the cost of equity for TEP.

C. Other ROE Issues

Q. Please explain your concerns with Mr. Mease's Comparable Earnings Analysis.

A. Mr. Mease provides an identical Comparable Earnings analysis to that prepared by Mr. Parcell. My criticisms of Mr. Mease's Comparable Earnings analysis are addressed in my response to Mr. Parcell.

Q. Mr. Mease included a page of rebuttal testimony addressing the small size premium. Have you presented evidence for TEP on this topic?

A. No. I have not proposed a small size premium for TEP.

D. Fair Value Rate of Return

Q. Please summarize Mr. Mease's recommendation with respect to the FVROR for TEP.

A. Mr. Mease recommends a FVROR of 5.20 percent for TEP, which is derived by subtracting an inflation rate of 1.56 percent from his recommended WACC 6.76 percent.[71] Mr. Mease's inflation rate is based on a seven-year historical average

[71] Direct Testimony of Robert B. Mease, Schedule RBM- 3, at 1.

difference between the yield on Treasury Inflation Protected Securities ("TIPS") and comparable Treasury securities with similar liquidity and duration.

Q. Do you agree with the methodology Mr. Mease has used to derive the FVROR for TEP?

A. No, I do not. In recent rate cases for both TEP and UNS Electric, the Commission has applied a positive rate of return to the fair value increment of rate base in establishing the FVROR. Mr. Mease's analysis does not follow this approach and instead simply removes inflation from the entire cost of capital.

Q. Please explain why it is not appropriate to apply an inflation factor to the WACC.

A. Only the fair value increment of the capital structure should be reduced to reflect a lower return. The remainder of the capital structure should receive the OCROR. To reduce the return on the entire capital structure for inflation understates the return on the original cost rate base.

Q. How does your proposed methodology for estimating the FVROR address Mr. Mease's point regarding inflation in the FVRB?

A. The calculation proposed in my Direct Testimony is consistent with the methodology proposed by Staff. This approach establishes the Fair Value Increment, which is the difference between the OCRB and the FVRB and assigns a separate return to that component of the capital structure. As shown in Exhibit AEB-10 of my Direct Testimony, I calculate the FVROR by applying the Company's requested equity cost rate of 10.00 percent to the equity component of the OCRB, and the debt cost rate to the debt

component of the OCRB without adjustment. The Fair Value Increment is then assigned a cost rate equal to one half of the risk-free rate.

Q. Do you agree with the methodology used by Mr. Mease to estimate inflation?

A. No. Mr. Mease's inflation rate analysis is entirely historical and considers only the period since the Great Recession, from 2009 through 2015. Furthermore, Mr. Mease's estimate of inflation has been declining since 2011. Furthermore, as discussed in the rebuttal testimony of Company Witness Grant, the methodology relied on by Mr. Mease is very sensitive to minor changes in expected inflation. As shown in Mr. Grant's rebuttal testimony, during periods of low inflation or deflation, the methodology used by Mr. Mease would produce a large return premium for most utilities. Conversely, during periods of high inflation, his proposed methodology would impose severe return penalties on most utilities. Significant variability in the revenue requirement resulting from this methodology exposes TEP to much greater risk than the proxy companies.

Q. What is your conclusion with respect to the appropriate return on FVROR for TEP?

A. I continue to support the methodology used in my Direct Testimony to establish the FVROR. That approach suggests a return on the Fair Value Increment between the projected risk free rate and the ROE. The methodology that I have employed is consistent with the approach proposed by Staff, though the inflation factors differ. Specifically, I conclude that the minimum ROR that should be applied to the Fair Value "Increment" of rate base is the real risk free rate, which I estimate to be 2.84 percent.[72] The Company continues to advocate the use of 50.00 percent of the risk free rate in the

[72] Direct Testimony Exhibit AEB-11.

FVROR calculation in order to moderate the effect of the rate increase on customers. As discussed in my Direct Testimony, applying 50 percent of the risk free rate to the Fair Value Increment, coupled with using a 10.35 percent ROE, results in a FVROR of 5.69 percent. Based on a 10.00 percent ROE, and taking into account adjustments the Company has made to the OCRB and Fair Value Increment of rate base, I now recommend a FVROR of 5.57 percent, calculated as shown in Table 4 below:

Table 4: Revised FVROR[73]

Capital	Amount ($M)	Weighting	Weighted Amount ($M)
Original Cost Rate Base	$2,066.3	50%	$1,033.2
Replacement Cost New Less Depreciation	$3,649.4	50%	$1,824.7
Fair Value Rate Base			$2,857.9
Appreciation above OCRB			$ 791.5

Capital	Amount	Percentage	Cost Rate	Weighted Cost Rate
Long-term Debt	$1,032.6	36.13%	4.32%	1.56%
Common Equity	$1,033.8	36.17%	10.00%	3.62%
OCRB	$2,066.4	72.30%		5.18%
Appreciation above OCRB	$ 791.6	27.70%	1.42%	0.39%
Total	$2,857.9	100%		5.57%

VI. RESPONSE TO DOD WITNESS MR. GORMAN

Q. Please provide a summary of Mr. Gorman's testimony and recommendations.

A. Mr. Gorman estimates a range of returns of 8.90 percent to 9.70 percent and recommends a cost of equity at the midpoint of his estimated range, *i.e.*, 9.30 percent.[74] The upper end of Mr. Gorman's estimated range (*i.e.*, 9.70 percent) is based on his risk premium analysis,[75] and the lower end (*i.e.*, 8.90 percent) represents the midpoint of his Constant Growth DCF analysis (using analyst growth rates) and his CAPM analysis.[76] Mr.

73 See Exhibit AEB-R-1.
74 Direct Testimony of Michael P. Gorman, at 2.
75 *Ibid.*, at 26.
76 *Ibid.*, at 30, 36.

Gorman appears to recognize that his Multi-Stage DCF results of 7.99 percent and his Constant Growth DCF results based on the Sustainable Growth model of 8.06 percent fall far below the results of his other models, since these results have been excluded from his range of returns. In fact, only Mr. Gorman's Bond Yield plus Risk Premium analysis produces an ROE estimate that is generally consistent with the authorized ROEs for vertically-integrated electric utilities in 2015 and 2016. Mr. Gorman's Constant Growth DCF model using growth rates based on either analyst EPS forecasts or sustainable growth rates, his Multi-Stage DCF model, and his CAPM analysis all produce ROE estimates that are well below any authorized return on equity for a vertically-integrated electric utility in the last 25 years.

Q. What are the major areas of disagreement between you and Mr. Gorman?

A. Mr. Gorman and I disagree on the inputs and assumptions used in several analyses including: (1) the growth rates used in the Constant Growth DCF model; (2) the long-term growth rate used in the Multi-Stage DCF Model; (3) the appropriate market risk premium for the CAPM analysis; (4) the approaches used in our respective Risk Premium analyses; (5) Mr. Gorman's conclusion that a 9.30 percent ROE is supportive of TEP's financial integrity; and (6) Mr. Gorman's recommended equity ratio for TEP.

A. Proxy Group Selection

Q. Please explain areas of difference between your proxy group and Mr. Gorman's proxy group for TEP.

A. Mr. Gorman and I have each developed a proxy group to estimate the cost of equity for TEP. However, we have used somewhat different screening criteria in developing our respective proxy groups. Mr. Gorman's proxy group consists of 29 electric utility

companies, whereas my proxy group was comprised of 12 electric utilities. While many of Mr. Gorman's screening criteria are similar to mine, there are several important differences that affect the composition of our respective proxy groups. First, Mr. Gorman screens for companies that are classified as "Regulated" or "Mostly Regulated" by the Edison Electric Institute, whereas I have screened based on the percentage of regulated operating income and the percentage of regulated income derived from electric utility operations. The EEI criteria for "Regulated" is investor-owned electric companies with greater than 80 percent of total assets regulated, and for "Mostly Regulated" is 50 to 80 percent of total assets regulated.[77] By contrast, I have screened out companies that do not derive greater than 90 percent of their regulated operating income from regulated electric operations.

Q. What is your conclusion with respect to proxy group for TEP?

A. Mr. Gorman's proxy group is much less focused on regulated electric utility operations than my group. For that reason, I believe that my proxy group is comprised of more risk-comparable companies than Mr. Gorman's. When I employ my DCF and CAPM assumptions using Mr. Gorman's proxy group, there is a substantial difference in the mean results of the Constant Growth DCF analysis. As discussed later in my Rebuttal Testimony, this difference is primarily due to Mr. Gorman's inclusion of Entergy and First Energy, both of which have negative earnings per share growth rates from Zack's and Reuters consensus forecasts, and very low SNL growth rates. As shown in Table 5, the results of the Constant Growth DCF analysis using Mr. Gorman's proxy group are 44 basis points lower than the results for my proxy group.

[77] EEI, 2015 Financial Review, Annual Report of the U.S. Investor-Owned Electric Utility Industry (2015) at i, v.

Table 5: Gorman Proxy Group Results v. Bulkley Proxy Group Results

	CONSTANT GROWTH DCF			MULTI-STAGE DCF		CAPM	
				Mean Growth Rate			
	Low	Mean	High	Ver. 1	Ver. 2	B'berg	VL
Average:	-0.49%	-0.44%	-0.23%	0.10%	-0.16%	0.13%	-0.14%
Median:	-0.25%	-0.03%	0.42%	0.17%	-0.09%	0.13%	-0.15%

B. DCF Analyses

Q. Please summarize Mr. Gorman's DCF analyses.

A. Mr. Gorman conducts three DCF analyses, two forms of the Constant Growth DCF and a Multi-Stage DCF analysis. The results of Mr. Gorman's DCF analyses range from 7.89 percent to 8.71 percent.[78] Mr. Gorman concludes that his DCF studies support a return on equity of 8.70 percent based on the Constant Growth DCF results, which he considers to be a reasonable high-end DCF return estimate.[79] All of Mr. Gorman's ROE estimates are well below any authorized ROE for a vertically-integrated electric utility in the last 25 years.

i. Constant Growth DCF

Q. How did Mr. Gorman develop his Constant Growth DCF analyses?

A. Mr. Gorman's Constant Growth DCF analyses are based on the use of analysts' earnings growth estimates in the first analysis and a measure of "Sustainable Growth" in the second specification of the model.[80]

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78 Direct Testimony of Michael P. Gorman, Table 4.
79 Direct Testimony of Michael P. Gorman, at 36.
80 *Ibid.*, at 25, 27.

Q. Why are Mr. Gorman's Constant Growth DCF results so much lower than recent market benchmarks?

A. Mr. Gorman's first Constant Growth DCF analysis relies on an average of the analysts' earnings growth rates and produces returns in the range of 8.70 percent. This result, which Mr. Gorman characterizes as a reasonable high-end DCF estimate, is below the low end of the range he has established for his final recommendation. The low result is largely attributable to the extremely low growth rates that Mr. Gorman has relied on for several proxy group companies. For example, as shown in Exhibit MPG-4, Mr. Gorman relies on earnings growth rates of 0.50 percent for Entergy Corporation, and 0.40 percent for FirstEnergy. Relying on these growth rates in perpetuity in the Constant Growth form of the DCF model results in estimated returns for these two companies of 5.01 percent and 4.58 percent respectively.[81] These returns, which are more consistent with a debt return, not equity, influence the mean result of 8.71 percent.

Q. Have you made any adjustments to Mr. Gorman's Constant Growth DCF analysis using consensus analyst earnings growth rates?

A. Yes, I have. In my view, it is not reasonable to believe that investors would purchase shares in companies that are expected to have negative real earnings growth over the next five years. If those results are excluded from Mr. Gorman's DCF analysis, the mean ROE increases to 9.0 percent. While this is still well below returns for comparable risk electric utilities, it is 29 basis points higher than Mr. Gorman's mean DCF result using EPS growth rates.

[81] Exhibit MPG-5.

Q. What are the results from Mr. Gorman's "Sustainable Growth" DCF model?

A. Mr. Gorman's Sustainable Growth DCF analysis produces mean and median ROE results of 8.06 percent and 7.72 percent, respectively.[82] While Mr. Gorman devotes considerable effort to the support of the sustainable growth model, he ultimately does not rely on the results of this model when setting the ROE from his DCF analyses.

Q. Do you agree with the use of the "Sustainable Growth" estimate?

A. No, I do not. As discussed in my response to Mr. Parcell, there is academic support for the theory that earnings growth may not occur along with increases in the retention ratio. This contradicts the fundamental principles of the sustainable growth rate. Furthermore, by adopting Value Line's earned ROE estimates, Mr. Gorman has effectively pre-supposed the Return on Common Equity projected by Value Line for the proxy group companies. As shown on Exhibit MPG-7, the average Value Line earned ROE estimates for the companies in Mr. Gorman's proxy group is 10.38 percent, or more than 230 basis points higher than Mr. Gorman's DCF estimate using sustainable growth rates.[83] Moreover, as discussed in my response to Mr. Parcell, in Order 531, the FERC has recently abandoned the use of sustainable growth rates in the DCF analysis and has indicated that a two-stage analysis using long term growth estimates is more appropriate for electric utilities.

Q. Does Mr. Gorman disagree with the earnings growth estimates that you used in your Constant Growth DCF model?

A. Yes, Mr. Gorman states that the DCF results presented in my Direct Testimony are overly optimistic because the earnings growth rate that I have relied on is not a reasonable

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82 Direct Testimony of Michael P. Gorman, Table 4.

83 Exhibit MPG-7, column 5.

estimate of long-term sustainable growth. Mr. Gorman suggests that the growth rate used in the DCF model cannot be higher than economists' predictions of GDP growth, which he estimates to be 4.2 percent.[84]

Q. What is your response to Mr. Gorman?

A. Mr. Gorman's own DCF recommendation contradicts his concern with the earnings growth rates used in my analysis. In order to support Mr. Gorman's recommended ROE of 9.30 percent using his Constant Growth DCF model, it would be necessary to rely on an average growth rate of 5.70 percent.[85]

ii. Multi-Stage DCF Analysis

Q. Please summarize Mr. Gorman's Multi-Stage DCF analysis.

A. Mr. Gorman also performs a Multi-Stage DCF analysis. In the first stage of his analysis (years 1-5), Mr. Gorman relies on consensus analyst EPS growth projections. In the second stage (years 6-10), the EPS growth rates are increased or decreased based on the difference between the short-term growth rate in Stage 1 and the long-term growth rate in Stage 3. In the third stage (starting in year 11), the growth rate is based on Mr. Gorman's estimate of projected GDP growth of 4.20 percent.[86] Mr. Gorman's Multi-Stage DCF analysis produces ROE estimates of 7.99 percent (mean) and 7.89 percent (median). Similar to the results of the Mr. Gorman's Sustainable Growth model, these ROE estimates are well below the authorized ROE for any vertically-integrated electric utility in the past 25 years. Furthermore, Mr. Gorman does not rely on his Multi-Stage DCF results in developing his range of results or his ROE recommendation.

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84 Direct Testimony of Michael P. Gorman, at 56.

85 Derived by iteratively solving for the growth rate using the constant growth formula employed by Mr. Gorman. [((D/P)x(1+g))+g= ROE]; where D=$1.82, P=$53.47 and ROE = 9.30%.

86 Direct Testimony of Michael P. Gorman, at 30,32.

Q. Do you agree with the long-term growth rate in Mr. Gorman's Multi-Stage DCF Model?

A. No, I do not. Mr. Gorman assumes a long-term growth rate of 4.20 percent, which is the average of five and ten-year GDP growth rate estimates as reported by Blue Chip Economic Indicators ("Blue Chip").[87] Mr. Gorman's GDP growth projection is more than 110 basis points below the long-term historical growth rate in nominal GDP reported by the U.S. Bureau of Economic Analysis. As discussed in my response to Mr. Parcell, there is support in the investment community for the use of historical real GDP growth and projected inflation as an estimate of nominal GDP growth.

Q. What long-term GDP growth rate would Mr. Gorman need to use in his Multi-Stage DCF analysis to support his ROE recommendation of 9.30 percent?

A. While Mr. Gorman is critical of my long-term GDP growth rate of 5.40 percent as being too high, in order to arrive at his 9.30 percent ROE recommendation, he would need to use a GDP growth rate of 5.84 percent[88] in his Multi-Stage DCF analysis. This implied growth rate is 164 basis points higher than the 4.20 percent GDP growth rate Mr. Gorman uses, and 44 basis points higher than my long-term GDP growth rate that Mr. Gorman criticizes as being too high.

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87 *Ibid.*, at 27, and Schedule MPG-10.

88 Derived by using Schedule MPG-10 to solve for the long-term growth rate that would result in an ROE of 9.30 percent using Mr. Gorman's multi-stage DCF model.

Q. What is your conclusion regarding the appropriate GDP growth rate for the Multi-Stage DCF analysis?

A. In my view, current estimates of real GDP growth are understated relative to the long-term average because recent economic weakness is over-emphasized in current projections. For that reason, I believe it is reasonable to use historical long-term real GDP growth in conjunction with projected inflation as the terminal growth rate in the Multi-Stage DCF model.

C. CAPM Analyses

Q. Please summarize Mr. Gorman's CAPM analyses.

A. Mr. Gorman develops a range of CAPM estimates of 8.01 percent to 9.44 percent, based on an average of two estimates of the MRP. Mr. Gorman's first estimate of the MRP (7.90 percent) is based on the long-term historical arithmetic average real market return over the 1926-2014 period as reported by Morningstar, which he then adjusts for current inflation forecasts.[89] The second estimate of the MRP (*i.e.*, 6.00 percent) is based on the historical difference between the return on the S&P 500 and the total return on long-term government bonds.[90] Finally, Mr. Gorman uses the Blue Chip projected yield on 30-year Treasury bonds of 3.50 percent as his risk free rate, together with Beta coefficients provided by Value Line to calculate his CAPM result.[91] Mr. Gorman's CAPM analysis produces a return of 8.01 percent to 9.44 percent and yields an average ROE estimate of 9.10 percent.[92]

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89 *Ibid.*, at 46,47.
90 *Ibid.*, at 47.
91 *Ibid.*, at 45,46.
92 *Ibid.*, at 49.

Q. Do you agree with the historical market risk premiums Mr. Gorman has used in his CAPM analysis?

A. No, I do not. As discussed in my response to Mr. Parcell, Mr. Gorman's CAPM analysis fails to reflect the inverse relationship between interest rates and market risk premia. That is, as interest rates decrease, the market risk premium increases, and vice versa. Mr. Gorman's use of a historical MRP fails to accurately reflect current market conditions.

Q. Why do you believe that the historical estimate of the MRP does not properly reflect current capital market dynamics?

A. Mr. Gorman employs an MRP based on the historical relationship between the returns on the S&P 500 and long-term government bonds. Table 6 shows that from 2007-2009 the historical MRP decreased even as market volatility (the primary statistical measure of risk) significantly increased. As discussed previously, Mr. Parcell's Schedule 8, which estimates historical MRPs, also demonstrates this.

Table 6: Historical Market Risk Premium and Market Volatility

	Market Volatility	Annual Market Return	Historical Market Risk Premium[93]
2009	31.48	26.46%	6.70%
2008	32.69	-37.00%	6.50%
2007	17.54	5.49%	7.10%

The assumption that investors would expect or require a lower risk premium during periods of increased volatility is counter-intuitive and leads to unreliable analytical results. The relevant objective in the application of the CAPM is to ensure that all three components of the model (*i.e.,* the risk-free rate, Beta, and the market risk premium) are

93 *Ibid.,* at 59. The Historical Market Risk Premium equals total return on large company stocks less income only return on long-term government securities. Data is as reported by Ibbotson for each year.

consistent with market conditions and investor perceptions. Assuming a lower market risk premium during periods when interest rates are artificially suppressed by Federal Reserve monetary policy is at odds with that premise.

Q. Does Mr. Gorman have any objections to your specification of the CAPM?

A. Yes, Mr. Gorman asserts that my DCF-derived MRP estimate is based on a growth rate component that is "far too high" to be an outlook for "sustainable" long-term market growth.[94]

Q. How do you respond to Mr. Gorman's conclusion on your estimated market return and MRP?

A. The MRP developed in my Direct Testimony is forward-looking and is based on the required return on the S&P 500 Index less the 30-year Treasury Bond Yield. The required return on the S&P 500 is calculated using the Constant Growth DCF model applied to the companies in the S&P 500 index for which long-term earnings projections are available. As I discussed more fully in my response to witness Parcell, the same method was endorsed by the FERC in Opinion No. 531-B as the appropriate manner to calculate the forward-looking MRP in the CAPM analysis.[95]

Q. Is Mr. Gorman's position regarding your DCF-derived market return consistent with his own approach to the CAPM analysis?

A. No, it is not. In his own CAPM analysis, Mr. Gorman uses a market return estimate of 12.10 percent.[96] Assuming that his market return estimate includes a dividend yield

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94 Direct Testimony of Michael P. Gorman, at 62.

95 Opinion No. 531-B,147 FERC ¶ 61,234 Order on Rehearing (March 3, 2015) at para.109-111.

96 *Ibid.*, at 47.

component equal to the value in my DCF-derived market return (*i.e.*, 2.07 percent), Mr. Gorman's market return estimates imply earnings growth rates of 9.93 percent,[97] or more than twice the long-term nominal GDP growth rate (*i.e.*, 4.20 percent) that Mr. Gorman uses in his Multi-Stage DCF Model. Mr. Gorman does not explain the inconsistency between his use of a market return growth rate in the CAPM that is materially higher than his long-term GDP growth rate estimate on the one hand, and his rejection of the DCF-derived market return used in my CAPM analysis (based solely on his observation that my value is higher than estimates of long-term GDP growth) on the other.

As a practical matter, it is unclear why Mr. Gorman asserts that 4.20 percent is an appropriate benchmark of long-term growth when his reliance on this growth projection in his Multi-Stage DCF analysis resulted in estimated returns that he ultimately could not rely on.

D. Risk Premium Model

Q. Please summarize Mr. Gorman's Risk Premium analyses.

A. In addition to his CAPM analysis, Mr. Gorman performs two additional Risk Premium analyses to estimate the Company's cost of equity. Mr. Gorman's first approach calculates the equity risk premium by taking the difference between regulatory commission-authorized equity returns for electric utilities and long-term Treasury bond yields from 1986-2015. Mr. Gorman determines that the rolling five-year average equity risk premia is 5.40 percent within a range of 4.25 percent and 6.71 percent.[98] Based on the projected 30-year Treasury yield of 3.50 percent, and the equity risk premium range

[97] Note that, based on my DCF-derived market return calculation, the earnings growth rate equals ([market return] – [dividend yield]) / (1 + 0.5 x [dividend yield]).

[98] Exhibit MPG-12.

noted above, Mr. Gorman calculates a range of risk premium results from 7.75 percent (3.50 percent plus 4.25 percent) to 10.21 percent (3.50 percent plus 6.71 percent). Mr. Gorman arrives at an ROE of 9.60 percent by giving 75 percent weight to the high end of his range and 25 percent weight to the low end.[99]

Mr. Gorman's second Risk Premium approach calculates the average risk premium for the period 1986 through 2015 as the difference between the average authorized equity returns for electric utility companies and the concurrent A-rated utility bond yields. Mr. Gorman determines that the rolling five-year average equity risk premia is 4.03 percent within a range of 2.88 percent and 5.53 percent.[100] Mr. Gorman then develops a range of ROE estimates by adding the 2.88 percent and 5.53 percent equity risk premia to the 13-week average Baa-rated utility bond yield of 4.91 percent, to arrive at a range of 7.79 percent to 10.44 percent. Mr. Gorman arrives at an overall ROE estimate of 9.78 percent by giving 75 percent weight to the high end of his range and 25 percent weight to the low end.[101] Based on those two approaches (*i.e.*, the risk premium as a function of Treasury yields and of utility bond yields), Mr. Gorman calculates a range of ROE results from 9.60 percent to 9.80 percent and determines that the midpoint of 9.70 percent represents a reasonable ROE estimate.[102]

Q. Does Mr. Gorman rely upon his risk premium model in making his ROE recommendation?

A. Yes. The high end of Mr. Gorman's range (*i.e.*, 9.70 percent) is based on the results of his Risk Premium analysis.[103]

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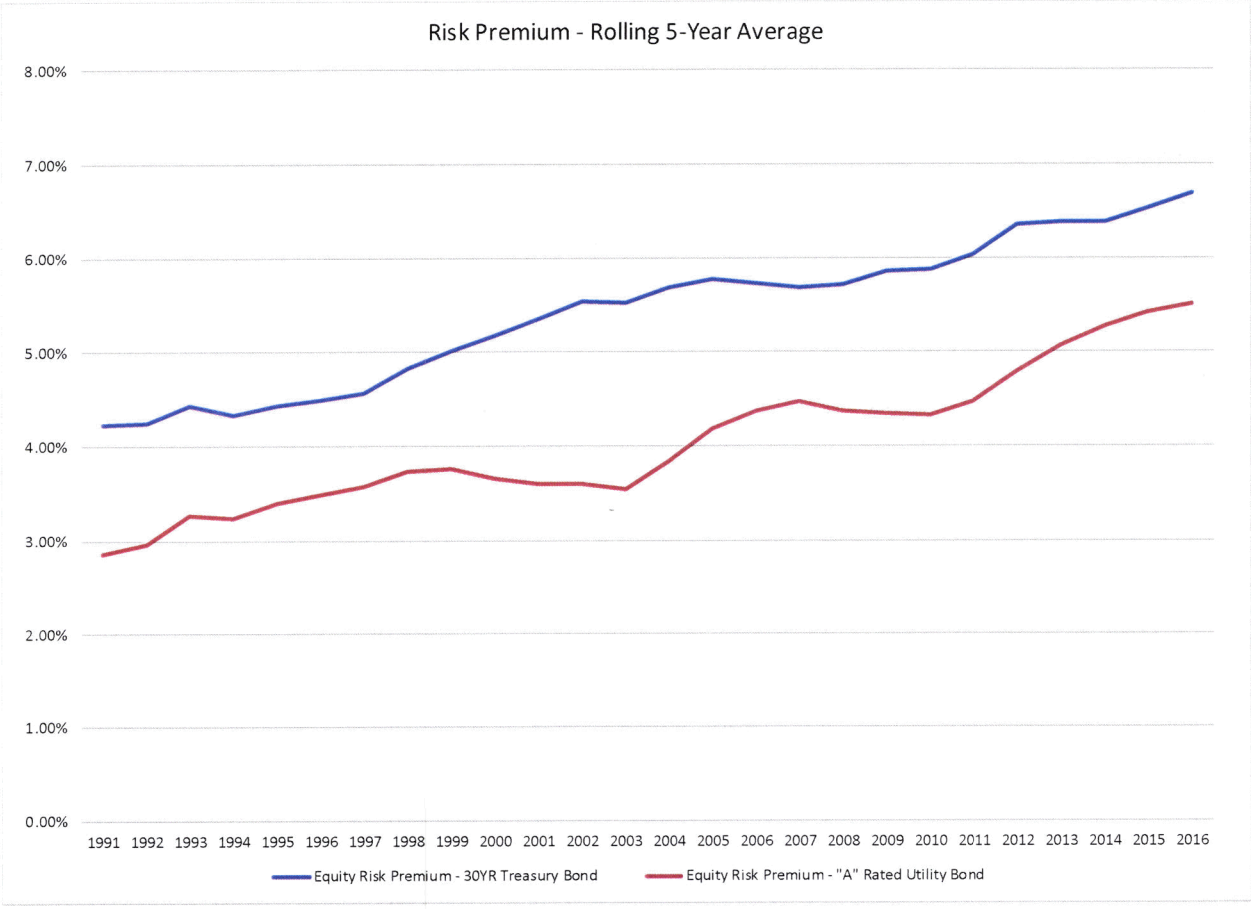
99 Direct Testimony of Michael P. Gorman, at 43.
100 Exhibit MPG-13.
101 Direct Testimony of Michael P. Gorman, at 43.
102 *Ibid.*
103 *Ibid.*, at 50.

Q. What are your specific concerns with Mr. Gorman's risk premium analyses?

A. Mr. Gorman creates a range of ROE estimates based on the rolling five year average risk premium as compared to Treasury bonds and A-rated utility bonds. However, as shown in Chart 33, the equity risk premium has been steadily increasing during the time period covered by Mr. Gorman's analysis. The low end of his range is represented by the five year rolling average equity risk premium in 1991, while the high end of his range is based on the five year rolling average equity risk premium in 2016.

Chart 3: Equity Risk Premium – 1991-2016 Rolling Five Year Average



Mr. Gorman offers no evidence as to why the average equity risk premium in 1991 is at all meaningful in establishing forward-looking ROE estimates in 2016. The high end of Mr. Gorman's range of Risk Premium estimates is 10.21 percent (based on Treasury yields) and 10.44 percent (based on utility bond yields). These are based on the average MRP for the five years ended 2016. Of the historical MRPs considered by Mr. Gorman, the most recent period would be most reflective of current and near term projected market conditions.

Q. What are the average results of Mr. Gorman's risk premium analysis using the most recent risk premium data?

A. Relying on the most recent five-year rolling average historical MRP, Mr. Gorman's estimated returns are 10.21 percent to 10.44 percent, the mean of which is 10.33 percent.

Q. Does Mr. Gorman's Direct Testimony address the inverse relationship between interest rates and risk premia?

A. Yes, Mr. Gorman disputes the inverse relationship between interest rates and risk premia.[104] In particular, Mr. Gorman claims that, while academic studies have shown that in the past there has been such an inverse relationship, the relationship has changed over time, particularly since interest rate volatility is lower now than it was in the 1980s. Mr. Gorman further suggests that I have ignored investment risk differentials in my regression analyses.

[104] Direct Testimony of Michael P. Gorman, at 54-55.

Q. Do you agree with Mr. Gorman's conclusions regarding your Risk Premium approach?

A. No, I do not. First, Mr. Gorman fails to recognize that a large body of research in addition to my own statistical analyses supports the inverse relationship between interest rates and equity risk premia. In addition, several of these studies were published after those that Mr. Gorman cites as evidence that this inverse relationship is a relic of the 1980s. As summarized in *New Regulatory Finance*:

> Published studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carelton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates—rising when rates fell and declining when interest rates rose. The reason for this relationship is that when interest rates rise, bondholders suffer a capital loss. This is referred to as interest rate risk.... Conversely in low interest rate environments, when bondholders' interest rate fears subside and shareholders' fears of loss of earning power dominate, the risk differential will widen and hence the risk premium will increase.[105]

Furthermore, Mr. Gorman's critique of my risk premium analysis is inconsistent with his own approach. Mr. Gorman states that the relationship between interest rates and equity risk premia "changes over time".[106] However, Mr. Gorman fails to account for any relationship between interest rates and equity risk premia in his own analysis. Further, he concludes that "current market perceptions of utility risk is about average relative to the historical time period," by reviewing credit spreads of utility bond yields. However, he comes to this conclusion by subtracting a projected bond yield of 3.5 percent from a 13-week average utility bond yield to calculate his credit spreads. One cannot infer the current state of market risk by subtracting a projected bond yield from historical bond yield information. If he wishes to derive any meaningful information from historical bond yields, he must use data from the same time periods. When he performed this

[105] Morin, Roger A., *New Regulatory Finance*, Public Utilities Reports, Inc. (2006), at 128.
[106] Direct Testimony of Michael P. Gorman, at 54-55.

analysis, it revealed that bond spreads were actually increasing for all but the very highest credit ratings, and indicates that there is more risk in today's market than the long term average.

E. Financial Integrity

Q. Does Mr. Gorman address whether his ROE recommendation will preserve the financial integrity of TEP?

A. Yes. Mr. Gorman assesses the reasonableness of his ROE recommendation by evaluating the *pro forma* effect that his recommended ROE would have on three of the Company's key financial ratios with the goal of ascertaining whether those ratios would still fall within S&P's guideline ranges sufficient for an investment grade rating.[107] Specifically, Mr. Gorman estimates the following financial ratios assuming that the Company earns his recommended ROE: (1) Total Debt to Total Capital; (2) Debt to Earnings Before Interest, Taxes, Depreciation, and Amortization ("EBITDA"); and (3) Funds From Operations ("FFO") to Total Debt. In his Schedule MPG-18, Mr. Gorman develops his *pro forma* financial ratio calculations based on TEP's retail cost of service as presented in this case and his recommended ROE of 9.30 percent. Mr. Gorman notes that TEP has an overall financial risk profile rating of "Significant" from S&P and proceeds to demonstrate that, assuming all other inputs to his *pro forma* financial analysis remain unchanged, his recommended ROE of 9.30 percent would be sufficient to maintain those three key financial ratios within the S&P guideline ranges for "Significant" or "Intermediate" financial risk. Based on that analysis, Mr. Gorman concludes that his recommendation would support an investment grade bond rating.[108]

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[107] *Ibid.,* at 51-52.
[108] *Ibid.,* at 52-53.

Q. Do you agree with Mr. Gorman's analysis and conclusion?

A. No, I do not. The fact that Mr. Gorman's ROE recommendation produces credit metrics that fall within a certain ratings category does not mean that the Company necessarily would achieve or maintain that rating because rating agencies consider factors other than financial ratios in the development of credit ratings. Moreover, Mr. Gorman's analysis assumes that TEP will earn its authorized ROE despite the persistent regulatory lag that is created in Arizona by the use of a historical test year. Lastly, from the standpoint of equity investors, the relevant consideration is whether the authorized ROE for TEP offers investors a comparable return as compared to prevailing returns available to investors in other utilities with commensurate risk. In that regard, Mr. Gorman's ROE recommendation of 9.30 percent is significantly lower than the average authorized ROE for integrated electric utilities of 9.73 percent for 2015 and 2016.

F. Capital Structure Recommendation

Q. Please summarize Mr. Gorman's proposed capital structure for TEP.

A. Mr. Gorman proposes a capital structure consisting of 48.69 percent common equity and 51.31 percent long-term debt, as compared to TEP's proposed capital structure of 50.03 percent common equity and 49.97 percent long-term debt.[109] In particular, Mr. Gorman testifies that the average common equity ratio for the companies in his proxy group is 47.9 percent based on data published by Value Line and 45.6 percent based on data provided by SNL (including short term debt).[110] Mr. Gorman states that his recommended capital structure is slightly higher than but comparable to the proxy group.[111]

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109 Direct Testimony of Michael P. Gorman, at 5.
110 Direct Testimony of Michael P. Gorman, at 23.
111 *Ibid.*

Q. Have you reviewed the analysis of proxy company capital structures that Mr. Gorman relies on?

A. Yes. Mr. Gorman relies on two data sources for his analysis: Value Line and SNL. Value Line only reports the capital structures of the holding companies, not the regulated utility subsidiaries. As shown in my Direct Testimony (Exhibit AEB-9), SNL does report the capital structures of the proxy companies. It appears, however, that the data that Mr. Gorman relied on from SNL was the capital structure at the holding company level, including short-term debt.

Q. Do you agree with the analysis prepared by Mr. Gorman?

A. No, I do not. The relevant capital structure for comparison purposes is at the operating company level, not the holding company, as used by Mr. Gorman. The Commission in this case will be setting the capital structure for TEP, the operating company, which will be used to finance investments in rate base that provides electric utility service to customers. Mr. Gorman's analysis includes corporate-level debt that is not part of the regulated or financial capital structure of the operating utilities.

As discussed in my Direct Testimony, TEP's proposed common equity ratio of 50.03 percent is below the mean common equity ratio of the operating companies in my proxy group of 54.00 percent.[112] The Company's proposed capital structure is based on the test year actual capital structure and pro forma adjustments for a pending bond redemption for the period ending June 20, 2015. In addition, it is consistent with the range of equity ratios at the operating company level for the electric utility companies in my proxy

[112] Direct Testimony of Ann E. Bulkley, at Exhibit AEB-9.

group, and with the requirements to maintain the Company's current credit rating. For those reasons, I continue to support TEP's proposed capital structure as reasonable.

G. Mr. Gorman's Adjustments to Ms. Bulkley's Analysis

Q. Mr. Gorman provides adjustments to the assumptions used in the ROE analyses you provided in Direct Testimony in this proceeding, the results of which are summarized in Table 7 of his testimony. Do you agree with the proposed adjustments?

A. No, I do not. Mr. Gorman's adjustments to the assumptions used in my analyses appear to be arbitrary and are not consistent with his own testimony. While Mr. Gorman criticizes my Constant Growth DCF analysis stating that it is based on excessive, unstainable growth rates, Mr. Gorman makes no adjustment to my Constant Growth DCF results, but instead indicates that they should be considered at the high end of the range of results.

Mr. Gorman criticizes the GDP growth estimate used in my Multi-Stage DCF analysis and adjusts the long-term growth rate to rely on the 4.2 percent growth rate that he uses in his Multi-Stage model. As discussed in my response to Mr. Gorman's analysis, the long-term GDP growth rate he uses in his analysis is unreasonably low and produces results that he ultimately does not rely on in developing his recommended ROE. As noted in my response to his Multi-Stage DCF analysis, in order to derive an ROE of 9.3 percent, which is his recommendation, it would be necessary to use a GDP growth rate of 5.83 percent. Therefore, since Mr. Gorman implicitly does not rely on his long-term GDP growth rate to determine his ROE recommendation, I do not believe it is appropriate to adjust my analysis to reflect his lower long-term growth rate.

Regarding my CAPM, Mr. Gorman suggests that this analysis is based on inflated market risk premiums and reduces my risk premium estimates, stating that they are inflated and updates my risk free rate. As discussed in my response to Mr. Gorman, the methodology used to develop the MRP estimates that I have relied on has been supported by the FERC and is more reasonable than relying on the historical MRP.

Finally, Mr. Gorman suggests that my bond yield risk premium analysis is based on inflated utility equity risk premiums and stale Treasury yields. I have already addressed our differing opinions regarding these analyses in my response to Mr. Gorman.

Q. Mr. Gorman indicates that based on credit rating, TEP and both your proxy group and Mr. Gorman's proxy groups are risk-comparable. Do you agree?

A. No, I do not. Though I do agree that ratings agencies perform a thorough review of risk, they do so with the focus of determining to what extent those risks are likely to impact the company's ability to repay its debt obligations. However, in this case, we are attempting to assess how those risks would impact the returns available for equity holders. Though the credit ratings may indicate a broad measure of risk, they do not address the risks that are applicable to equity holders.

H. Fair Value Rate of Return

Q. Please briefly summarize Gorman's testimony as it relates to the Company's FVROR.

A. Mr. Gorman's position regarding the FVROR is that the net operating income should be approximately the same using a FVRB as it would be using the OCRB.

Q. How does Mr. Gorman calculate the FVROR?

A. Mr. Gorman calculates the return on the Fair Value increment by estimating inflation and subtracting that from the nominal risk-free rate to estimate an implied real risk-free rate. Mr. Gorman then relies on 50 percent of the real risk-free rate as the return on the fair value increment. This methodology is similar to the methodology that I relied on in my Direct Testimony.

Q. Do you agree with Mr. Gorman's calculation?

A. No I do not. Mr. Gorman has not relied on consistent data to perform his calculation. Mr. Gorman suggests that it is more appropriate to use current observable yields on Treasury bonds and projected Treasury yield over the next two years, because this period of Treasury bond yields is likely to reflect TEP's actual capital costs during the period rates will be in effect.[113] Mr. Gorman states that the five and 10 year Treasury bond yields that I have relied on "will not impact TEP's cost of capital when the rates are in effect".[114] Despite that concern, Mr. Gorman relies on those long-term estimates of inflation to estimate his inflation rate. As shown in MPG-22, Mr. Gorman updates the inflation measures that I relied on in my Direct Testimony, extending the forecast period for an

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113 Direct Testimony of Michael P. Gorman, at 74.
114 *Ibid.*

additional year to 2027. This has the effect of increasing the inflation factor that is used to convert the nominal risk-free rate to the real risk-free rate. While Mr. Gorman's schedule demonstrates that interest rates are projected to increase, even from the filing of my Direct Testimony, Mr. Gorman relies on the average of a historical nominal risk-free rate and a projected nominal risk-free rate through the third quarter of 2014. His estimate of the real risk-free rate is then developed by reducing the historical and short-term nominal risk-free rate by inflation expectations that are projected through 2027.

Q. How would you adjust Mr. Gorman's calculation?

A. The development of the nominal risk-free rate and the inflation factor that is used to estimate the real risk-free rate should be based on similar projected periods. As shown in my Direct Testimony and in Mr. Gorman's MPG-22, the estimate of the return on the fair value increment that was developed in my recommendation is internally consistent with respect to forecast periods.

Q. Have you calculated the effect of this change on Mr. Gorman's estimated return on the fair value increment?

A. Yes, I have. As shown in Exhibit AEB-R-2, relying only on the projected analysis, because it is the relevant analysis in a forward-looking estimate of the cost of capital, the average inflation projection is 2.27 percent and the average nominal Treasury bond yield is 4.45 percent. The resulting implied real risk-free rate is 2.13 percent. The return on the fair value increment would be 1.07 percent, or 61 basis points higher than Mr. Gorman's estimated return. Applying a cost rate of 1.07 percent to the fair value increment in the calculation of the FVROR presented in my Direct Testimony would result in a FVROR of 5.60 percent.

VII. RESPONSE TO WAL-MART WITNESS TILLMAN

Q. Please briefly summarize Mr. Tillman' testimony as it relates to the Company's ROE.

A. Mr. Tillman does not recommend a specific ROE. Rather, he observes that the proposed recommendation exceeds recently authorized ROEs across the country which, according to Mr. Tillman, have averaged 9.74 percent for all electric utilities from 2013 through 2016, and 9.89 percent for vertically-integrated electric utilities.[115] Mr. Tillman also testifies that the industry trend has been toward declining ROEs for electric utilities over this time period.[116] Mr. Tillman concludes that the Commission should approve an ROE no higher than the currently allowed ROE of 9.50 percent unless the Commission "determines that UNSE has sufficiently and substantially demonstrated a significant change in the economic environment faced by the Company"[117] since the Commission's decision in the 2012 rate case.

Q. What are your responses to Mr. Tillman on those points?

A. Mr. Tillman observes that the recommended ROE is higher than returns authorized for electric utilities by other regulatory commissions. He reports that authorized returns for electric utilities have ranged from 8.72 percent to 10.95 percent from 2013-2016 (to date); and that the average authorized ROE for that period is 9.74 percent. Mr. Tillman recommends an allowed ROE of no more than 9.50 percent for TEP, which is 24 basis points below the average ROE of all electric utilities included in Mr. Tillman's analysis. However, TEP is a vertically integrated electric utility with substantial generation assets. As I discussed in my response to Mr. Parcell, TEP has greater risk than most utilities,

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115 Direct Testimony of Gregory Tillman, at 12.
116 *Ibid.*
117 *Ibid at 14.*

including other vertically integrated electric utilities, and as a result should be authorized a higher return. Mr. Tillman does report that the average for vertically-integrated electric utilities over the same time period (2013-2016) was 9.89 percent,[118] which is nearly 40 basis points above Mr. Tillman's recommendation.

Furthermore, though ROE has been trending down from 2013-2016, there is no justification for lowering the allowed return further, particularly given expectations for interest rate increases. Both my Direct and Rebuttal Testimony explain how current economic and forward-looking capital market conditions are evolving and how wider credit spreads and investor expectations for higher interest rates provide support for the conclusion that the cost of equity will be trending higher from current levels.

If the Commission finds recently authorized ROEs to be a useful benchmark in this proceeding, of the Company's revised requested ROE of 10.00 is within the range of ROEs (from 9.00 percent to 10.95 percent) authorized for vertically integrated electric utilities from 2013-2016 on a nationwide basis, while Mr. Mease's and Mr. Parcell's recommended ROEs of 9.30 percent and 9.35 percent, respectively, are lower than all but one such authorization for integrated electric utilities, as shown in Chart 1.

Q. Mr. Tillman believes the UNSE stipulation to a 9.5 percent ROE should be considered by the Commission in its decision regarding the authorized ROE for TEP. Do you agree?

A. No, I do not. As Mr. Tillman notes, the stipulation was negotiated between UNSE and several parties. Stipulations are based on a balancing of issues, where there are many

[118] SNL Database.

trade-offs to reach agreement across many parties. It is inappropriate to select one element of a negotiated agreement, in isolation and which was based on specific circumstances, and attribute the results of that agreement to TEP, a company with a completely separate set of circumstances.

VIII. CONCLUSIONS AND RECOMMENDATION

Q. Please summarize your conclusions regarding the appropriate ROE for TEP.

A. While the average authorized ROE declined in 2015, there is considerable variability in the range of authorized ROEs. Based on the risk factors identified for TEP, I believe that it is appropriate to set the ROE above the mean of the analytical results. As described in the Rebuttal Testimony of TEP witness Grant, the Company has updated its non-fuel revenue requirement using a 10.00 percent ROE, a value at the low end of my recommended range. I conclude that the Company's requested ROE of 10.00 percent is conservative based on the results of the ROE estimation methodologies, recently authorized ROEs for other vertically integrated electric utilities, the risk factors identified for TEP, and investors' expectation of market conditions over the period that rates will be in effect. ROEs at the levels proposed by the Opposing ROE witnesses are not reasonable and do not meet the standards established in *Hope* and *Bluefield* for a fair return.

Q. What is your recommendation for the FVROR for TEP?

A. Based on a 10.00 percent ROE, and a 1.42 percent return on the Fair Value Increment of rate base, I believe that a FVROR of 5.57 percent is reasonable and appropriate for TEP.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

Exhibit AEB – R – 1

UNS ELECTRIC
FAIR VALUE RATE OF RETURN
ARIZONA STAFF METHODOLOGY

	Amount ($M)	Weighting	Weighted Amount ($M)	
Original Cost Rate Base (OCRB)	$ 2,066.3	50.00%	$ 1,033.2	[1]
Replacement Cost New, Depreciated Rate Base (RCND)	$ 3,649.4	50.00%	1,824.7	[2]
Fair Value Rate Base (FVRB)			2,857.9	[3]
Appreciation Above OCRB			$ 791.5	[4]
FVRB / OCRB Multiple			1.38	

Capital	Amount ($M)	Percent	Cost Rate		Weighted Cost Rate	
Long-Term Debt	$ 1,032.5	36.13%	4.32%	[5]	1.56%	
Common Equity	1,033.8	36.17%	10.00%	[6]	3.62%	
Capital Financing OCRB	$ 2,066.3	72.30%			5.18%	
Appreciation Above OCRB Not Recognized on Utility's Books	791.5	27.70%	1.42%		0.39%	
Total	$ 2,857.9	100.00%			5.57%	[7]

[1] Exhibit DJL-R-1 attached to the testimony of TEP witness David J. Lewis.
[2] Exhibit DJL-R-1 attached to the testimony of TEP witness David J. Lewis.
[3] Equals [1] + [2]
[4] Equals [3] − OCRB
[5] Schedule D-1
[6] Equals Recommended ROE on OCRB
[7] Capital Financing OCRB + Return on Fair Value Increment

Exhibit AEB – R – 2

Tucson Electric Power Company

Correction of Mr. Gorman's Fair Value Cost Rate

Line	As Filed by Ms. Bulkley[1]		Corrected	
	Step 1		**Step 1**	
	Consumer Price Index		**Consumer Price Index[2]**	
1	2017-2021	2.30%	2018-2022	2.30%
2	2022-2026	2.30%	2023-2027	2.30%
3	Average	2.30%	Average	2.30%
	Consumer Price Index (All-Urban)		**Consumer Price Index (All-Urban)[3]**	
4	2015	2.37	2016	2.392
5	2026	2.94	2027	3.123
6	Compound Annual Growth Rate	1.98%	Compound Annual Growth Rate	2.46%
	GDP Chain-type Price Index		**GDP Chain-type Price Index[3]**	
7	2015	1.11	2016	1.119
8	2026	1.34	2027	1.398
9	Compound Annual Growth Rate	1.74%	Compound Annual Growth Rate	2.05%
			Market-Based Breakeven Inflation	
10			13-Week Average Nominal Yield[4]	4.30%
11			13-Week Average TIPS Yield[5]	0.92%
12			Breakeven Inflation[6]	3.34%
13	**Average Inflation Forecast**	**2.01%**	**Average Inflation Forecast**	**2.27%**
	Step 2		**Step 2**	
	Nominal U.S. Treasury Bond Yield, 30-Year		**Nominal U.S. Treasury Bond Yield, 30-Year**	
14	2017-2021	4.80%	2018-2022[7]	4.30%
15	2022-2026	5.00%	2023-2027[7]	4.60%
16	Average	4.90%	Average	4.45%
17	Implied Real Risk Free Rate	2.84%	Implied Real Risk Free Rate[8]	2.13%
18			13-Week Average 30-Year TIPS Yield[5]	0.92%
19			Average Real Risk Free Rate	1.53%
20	50.0% of Real Risk Free Rate	1.42%	**50.0% of Real Risk Free Rate**	**1.07%**

Sources & Notes:

[1] Exhibit AEB-10, page 2.

[2] *Blue Chip Economic Indicators*, March 10, 2016, page 14.

[3] EIA, *Annual Energy Outlook 2016: Early Release*, Table 20.

[4] Exhibit MPG-15, page 1.

[5] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org.

[6] (1+2.64%) / (1+0.92%) - 1.

[7] *Blue Chip Financial Forecasts*, June 1, 2016, page 14.

[8] (1+3.07%) / (1+2.13%) - 1.

Rebuttal Testimony of

Frank P. Marino

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-1933A-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

REBUTTAL TESTIMONY OF FRANK P. MARINO

ON BEHALF OF

OF TUCSON ELECTRIC POWER COMPANY

JULY 25, 2016

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Exhibits:

Exhibit FPM-R-1 TEP's response to AECC's data request AECC 1.3

Exhibit FPM-R-2 TEP's supplemental response to UDR 1.001, dated March 18, 2016

Exhibit FPM-R-3 Decision No. 75033

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Frank P. Marino and my business address is 88 East Broadway, Tucson, Arizona, 85702.

Q. Did you present direct testimony in this case?

A. Yes.

Q. **What is the purpose of your Rebuttal Testimony?**

A. I will respond to a variety of topics addressed in the Direct Testimonies of Commission Staff ("Staff"), the Residential Utility Consumers Office ("RUCO"), Arizonans for Electric Choice and Competition ("AECC"), and the International Brotherhood of Electrical Workers Local 1116 ("IBEW"). Specifically, I will address the following topics:

- Bonus Depreciation
- Accumulated Deferred Income Taxes Related to Intervenor Plant Adjustments
- Updates to Pro-Forma Adjustments in Direct Testimony
- Payroll Expense
- Short-Term Incentive Compensation
- Long-Term Incentive Compensation, SERP
- D&O Insurance and Severance Pay
- IBEW Allegation of Cross Subsidization

II. BONUS DEPRECIATION.

Q. Have there been any changes in tax law since TEP filed its rate case?

A. Yes. On December 18, 2015, the Protecting Americans from Tax Hikes Act of 2015 was signed into law. The Act extends 50 percent bonus tax depreciation through December 31, 2017, and includes a phase down to 40 percent bonus depreciation in 2018 and 30 percent in 2019.

Q. How does the extension of bonus depreciation impact this rate case?

A. Under prior law, 50 percent bonus tax depreciation expired December 31, 2014. As a result, in TEP's initial filing ADIT on post-test year plant and asset additions from January 1, 2015 to June 30, 2015 was calculated without the impact of 50 percent bonus depreciation. In TEP's Supplemental Response to AECC Data Request 1.3 attached as **Exhibit FPM-R-1**, TEP provided updated ADIT calculations, reflecting the extension of 50 percent bonus depreciation.

Q. Did Intervenor's file Direct Testimony reflecting the updated ADIT provided by TEP?

A. Yes. Staff and AECC included the updated ADIT amounts provided by TEP.

Q. Do you have any corrections to post-test year plant adjustments proposed by Staff and AECC?

A. Yes. The updated ADIT amounts provided by TEP reflect post-test year plant additions. Staff and AECC made adjustments to post-test year plant included in rate base without making the associated and offsetting ADIT adjustment. I discuss this in more detail in the next section.

III. ACCUMULATED DEFERRED INCOME TAXES RELATED TO INTERVENOR PLANT ADJUSTMENTS.

Q. Please explain how TEP determines whether the ADIT related to particular assets should be included in rate base?

A. TEP includes ADIT in rate base whenever the associated asset cost and accumulated depreciation are included in rate base.

Q. Did Staff and the Interveners accurately reflect this relationship in their Direct Testimony?

A. No. There are a number of Staff and Intervenor proposals to remove assets from rate base. However, in nearly all cases, the ADIT associated with the adjustment was not likewise removed resulting in an overstated adjustment and understated rate base. TEP witness Lewis has reflected the corrections to rate base that would need to accompany such adjustments.

IV. UPDATES TO PRO-FORMA ADJUSTMENTS IN DIRECT TESTIMONY.

Q. Please summarize the updates you made to the pro-forma adjustments you sponsor.

A. During the discovery process, I have identified errors related to certain pro-forma adjustments in my Direct Testimony that require correction. These include:

- Pension and Benefits
- Sundt Coal Handling Facilities Materials and Supplies
- Short-Term Incentive Compensation

Q. Please address the update to the Pension and Benefits pro-forma adjustment.

A. The update to the Pension and Benefits pro-forma adjustment captures certain benefit costs that were excluded from the initial adjustment addressed in my Direct Testimony at

page 32 lines 14 - 23. This was identified by TEP when responding to Data Request STF 7.15. The corrected information was provided as a supplemental response to UDR 1.001 on March 18, 2016 (the pertinent excerpt of the response to UDR 1.001 is attached as **Exhibit FPM-R-2**). Staff witness Mullinax acknowledged the need to correct the initial pro-forma adjustment in her Direct Testimony.

Q. **Please address the update to the Sundt Coal Handling Facilities Materials and Supplies pro-forma adjustment.**

A. My Direct Testimony at page 42, lines 13 – 16, addresses the recovery of remaining materials and supplies related to both the Sundt Coal Handling Facilities and San Juan Unit 2, which are both being retired early. After further review, we have determined that the amount of materials and supplies related to Sundt Coal Handling Facilities were understated in our initial filing.

Q. Please address the update to the Short-Term Incentive Compensation pro-forma adjustment.

A. In response to a RUCO data request, the Company discovered that the amount reported as test year short-term incentive compensation expense did not exclude the amount capitalized as A&G. The pro-forma adjustment proposed in my Direct Testimony at page 37, lines 19 – 24, was designed to produce a certain amount of recovery of Short-Term Incentive Compensation ("PEP"). The pro-forma adjustment has been corrected.

Q. Have these three updates been included in TEP's updated revenue requirement calculation?

A. Yes. TEP witness Lewis has included updates to these pro-forma adjustments as reflected in Exhibit DJL-R-1 to his Rebuttal Testimony.

V. PAYROLL EXPENSE.

Q. **Please summarize the Staff and Intervenor proposals related to Payroll Expense.**

A. Both Staff witness Mullinax and AECC witness Higgins propose to eliminate the increase in payroll costs of 2% for 2017 because it is an estimate and not known and measurable. IBEW witness Northrup supports the proposed 2% increase for 2017 for union employees, but opposes a similar adjustment for non-union personnel because the terms and conditions of their employment can change.

Q. **Do you agree that the 2017 payroll increase should be removed?**

A. No. Payroll increases are reasonable and necessary in order for TEP to remain competitive in the market for talent. Also the payroll changes are known and measurable with the exception of the 2017 non-union increase.

Q. **Why is a 2% union increase for 2017 reasonable?**

A. Since TEP filed this rate case, TEP and IBEW Local 1116 entered into a new collective bargaining agreement covering the three-year period January 2016 through December 2018. The agreement includes 2% annual increases in 2016 and 2017 and 2.5% increase in 2018. The agreement became effective January 4, 2016. Thus, this cost increase is in fact known and measurable. It is also representative of market pay increases.

Q. **Why is a 2% non-union increase for 2017 reasonable?**

A. Non-union increases have averaged approximately 2% per year for the past 6 years. The non-union increases are of the same magnitude of the negotiated union increases. This is a reasonable adjustment to test year expenses as 2017 represents the first full year that new rates will be in effect.

Q. **Which pro-forma adjustments does the 2% payroll increase impact?**

A. It impacts the following pro-forma adjustments:

- Payroll Expense
- Short-Term Incentive Compensation
- Long-Term Incentive Compensation
- Payroll Tax Expense

Q. **Please explain the Payroll Tax Expense adjustment.**

A. TEP's initial filing included a pro-forma adjustment to Payroll Tax Expense related to the pro-forma payroll increases. AECC witness Higgins identified an adjustment to Payroll Tax Expense related to his proposal to remove the 2% payroll increase for 2017. To the extent the 2% payroll increase for 2017 is removed from test year expense, I agree that Payroll Tax Expense should be adjusted accordingly.

VI. SHORT-TERM INCENTIVE COMPENSATION.

Q. **Please describe the adjustment you initially proposed for Short-Term Incentive Compensation.**

A. I proposed an adjustment that sets test year expense at a level equal to the average Short-Term Incentive Compensation ("PEP") expense for the test year ended June 30, 2015 and the prior year ended June 30, 2014. I then escalated the result by 2% for 2016 and 2017.

Q. **In what ways do the Staff and Intervenor proposals differ from that approach?**

A. Aside from the 2% payroll increase for 2017 that I addressed above, Staff witness Mullinax and RUCO witness Michlik each propose excluding 50% of PEP expense from test year expenses based on the premise that customers and shareholders both benefit from the program. AECC witness Higgins proposes to exclude 40% of the cost to

remove the portion of the expense attributable to the net income component of the program.

Q. **Do you agree with these proposals?**

A. I do not. My Direct Testimony at pages 34 - 40 addresses why PEP expense is a reasonable cost of providing service and how each component of PEP benefits customers. There is no basis to exclude elements of PEP in the ratemaking process. The financial performance of a utility sets the foundation for its ability to provide safe, reliable and affordable service. All of the components of PEP ensure that employees strive to provide the highest quality service at the lowest cost to customers. PEP is an integral component of TEP's compensation program which is designed to attract, retain and motivate a workforce while producing measurable benefits to customers at an overall cost that is comparable to market.

VII. LONG-TERM INCENTIVE COMPENSATION AND SERP.

Q. **Please summarize the Staff and Intervenor proposals related to Long-Term Incentive Compensation and SERP.**

A. Staff witness Mullinax, RUCO witness Michlik and AECC witness Higgins each propose to remove 100% of both LTI and SERP expense from the test year.

Q. **Do you agree with these proposals?**

A. No. My Direct Testimony at pages 40 – 42 addresses why these expenses are a reasonable cost of providing electric service.

Q. **Are you proposing any concessions with respect to the ratemaking treatment of LTI and SERP expense?**

A. Yes. While LTI and SERP are both reasonable and necessary components of TEP's compensation program, I propose as a concession in this case to remove these costs from test year expenses. The related adjustments have been included in TEP's revised revenue requirement as addressed by TEP witness Lewis. These concessions are made in the spirit of compromise, but TEP retains its right to request and receive recovery of LTI and SERP in future rate cases.

VIII. D&O INSURANCE AND SEVERANCE PAY.

Q. Please summarize the Staff and Intervenor proposals related to D&O insurance and severance pay.

A. Both Staff witness Mullinax and RUCO witness Michlik propose a 50/50 sharing of test year D&O insurance cost and they both propose to remove 100% of test year severance pay expense. I would note that Staff witness Mullinax removed from her calculation of pro-forma operating income the portion of severance pay that was capitalized.

Q. Are you willing to accept both of their proposed adjustments?

A. Yes, as a compromise for purposes of this rate case and while reserving TEP's right to request and receive full recovery of D&O insurance and severance costs in future rates. TEP witness Lewis has reflected the correct adjustment to both operating income and rate base associated with accepting these adjustments.

IX. IBEW ALLEGATION OF CROSS SUBSIDIZATION.

Q. Please summarize the allegation made by IBEW witness Northrup.

A. Mr. Northrup alleges that TEP cross-subsidizes UNS Energy and he asks that the Commission "focus its attention on this issue" and "pay special attention to whether UNS is being inappropriately enriched at the expense of TEP and, in turn, its patrons."

Q. Are you aware of any cross-subsidization of UNS Energy by TEP?

A. No. In my capacity of Vice President and Controller, I ensure that UNS Energy and its affiliates have appropriate policies and procedures in place to prevent cross-subsidization. These procedures use a fully-distributed costing methodology for assigning costs between regulated and non-regulated activities with an emphasis on direct assignment and cost causation whenever possible.

Q. Does UNS Energy and its affiliates have a Code of Conduct on file with the Commission?

A. Yes. UNS Energy and its affiliates, including TEP, have complied with a Code of Conduct which has been on file with the Commission since 2000 (see Decision No. 62767 (August 2, 2000)). The Code of Conduct sets forth the procedures for valuing and allocating intercompany transactions related to the transfer of assets and the provision of goods and services between UNS Energy affiliates. The Code of Conduct ensures that utility customers of TEP and its regulated utility affiliates are not impacted by cross-subsidization as it sets the methods upon which costs are allocated among regulated and non-regulated affiliates. In compliance with the ACC order approving Fortis' acquisition of UNS Energy, UNS Energy submitted a revised Code of Conduct to include all Fortis affiliates. See Decision No. 74689 (August 12, 2014) (Settlement Agreement Conditions

6 and 58). The Commission approved the revised Code of Conduct in Decision No. 75033 (April 23, 2015) attached as **Exhibit FPM-R-3**.

Q. Do UNS Energy's policies and procedures related to the Code of Conduct set forth any objectives?

A. Yes. UNS Energy and its affiliates utilize cost allocation procedures consistent with the Code of Conduct which have the principle objectives "to prevent or minimize, to the extent practicable, the potential for cross-subsidization of one activity or entity by another" while achieving "a proper balance between the desired precision of the cost allocation process with the cost of attaining such accuracy." See Attachment B, page 2 of **Exhibit FPM-R-3**.

Q. Does that conclude your Rebuttal Testimony?

A. Yes.

Exhibit FPM – R – 1

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO AECC FIRST SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE DOCKET NO. E-01933A-15-0322
January 14, 2016

AECC 1.3

Bonus tax depreciation. Using TEP's direct case as a starting point, what is the impact on the TEP's revenue requirement resulting from the five year extension of bonus tax depreciation in H.R. 2029 (as signed into law by President Obama on December 18, 2015)? Please provide the adjustments necessary on both a Total Company and ACC Jurisdictional basis necessary to reflect the impact of this extension on TEP's requested revenue increase. Please provide the workpapers used to support this response in Excel format with formulas intact.

RESPONSE: January 4, 2016

TEP is in the process of evaluating the H.R. 2029 through its year end close process and will respond as soon as possible.

RESPONDENT:

Jason Rademacher

WITNESS:

Frank Marino

SUPPLEMENTAL RESPONSE: January 14, 2016

For an updated Accumulated Deferred Income Tax pro forma adjustment that includes the impacts of the extension of bonus depreciation, see AECC 1.3 Bonus - Rate Base - Accumulated Deferred Income Taxes.xlsm. This update would reduce the overall revenue requirement by approximately $1.5 million. The Excel file is <u>not</u> identified by Bates numbers.

RESPONDENT:

Jason Rademacher

WITNESS:

Frank Marino

Exhibit FPM – R – 2

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO UNIFORM DATA REQUESTS - 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 18, 2016

WORKPAPERS:

UDR 1.001

Workpapers. Please provide a complete set of supporting workpapers for all schedules, analysis, calculations and witness testimony in TEP's filing. Provide all in Excel format with formulas and cross references intact where applicable.

SUPPLEMENTAL RESPONSE: March 18, 2016

- The adjustment for the Company's share of contributions to the employees' benefits expense (including 401(k) plan, medical, dental, vision, life and long-term disability benefit) was inadvertently omitted from the rate case filing. Please see revised pro-forma "Income – Pension & Benefits Revised.xlsm", as listed above.
- There was an inadvertent mathematical error in the working capital proforma adjustment. Please see Rate Base – Working Capital Revised.xlsm, as listed above.
- Please see Income-Payroll Expense-Revised.xlsm for the updated file which replaces linked numbers with values eliminating the errors when links are not activated, and adds page 10.
- Please see Income - Long Term Incentive Compensation-Revised.xlsm. The amount listed as Fortis Merger LTC Compensation Expense has been corrected.

RESPONDENT:

Regulatory Department

Exhibit FPM – R – 3

BEFORE THE ARIZONA CORPORATION COMMISSION

SUSAN BITTER SMITH
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
DOUG LITTLE
Commissioner
TOM FORESE
Commissioner

Arizona Corporation Commission
DOCKETED
APR 23 2015
DOCKETED BY

IN THE MATTER OF THE APPLICATION FOR APPROVAL OF THE REORGANIZATION OF UNS ENERGY CORPORATION ON BEHALF OF ITSELF AND ITS AFFILIATES UNISOURCE ENERGY SERVICES AND TUCSON ELECTRIC POWER COMPANY	DOCKET NOS. E-04230A-14-0011 & E-01933A-14-0011 DECISION NO. 75033 ORDER

Open Meeting
April 14-15, 2015
Phoenix, Arizona

BY THE COMMISSION:

FINDINGS OF FACT

1. On October 9, 2014, in compliance with Conditions 6 and 58 of the Settlement Agreement approved in Decision No. 74689 dated August 12, 2014, UNS Energy Corporation ("UNS Energy") and Fortis Inc. ("Fortis") submitted its proposed code of conduct regarding UNS Energy's and its regulated utility subsidiaries' affiliate transactions ("Code of Conduct") and the related proposed procedures for valuing and allocating intercompany transactions related to the transfer of assets and the provision of goods and services between affiliates ("Policies and Procedures"). The Code of Conduct updates UNS Energy's previously approved Code of Conduct to reflect the current conditions, including the acquisition of UNS Energy by Fortis.

2. UNS Energy and Fortis state that the Policies and Procedures reflect the long-standing valuation and cost allocation practices that have been in place since UNS Energy's acquisition of the Citizens Utilities' assets in 2002. They underlie the rates approved by the Commission for Tucson

Electric Power Company, UNS Electric, Inc. and UNS Gas, Inc. The Policies and Procedures also have been updated to reflect the current conditions in Arizona, including the acquisition of UNS Energy by Fortis.

3. Fortis and UNS Energy request Commission approval of the Code of Conduct and the Policies and Procedures to the extent required by Decision No. 74689 and the related Settlement Agreement.

4. Staff has reviewed the Code of Conduct and the Policies and Procedures and has made some clarifications as shown on the attached. Staff recommends that the Commission approve the Code of Conduct and the Policies and Procedures as contained in Attachments A and B.

CONCLUSIONS OF LAW

1. UNS Energy and its regulated affiliates are public service corporation within the meaning of Article XV of the Arizona Constitution and A.R.S. §§ 40-250 and 40-251.

2. The Commission has jurisdiction over UNS Energy and its regulated affiliates and of the subject matter of the Docket.

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ORDER

IT IS THEREFORE ORDERED that UNS Energy Corporation Code of Conduct and Policies and Procedures, attached hereto as Attachment A and Attachment B, respectively, are hereby approved.

BY THE ORDER OF THE ARIZONA CORPORATION COMMISSION

CHAIRMAN COMMISSIONER

COMMISSIONER COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I, JODI JERICH, Executive Director of the Arizona Corporation Commission, have hereunto, set my hand and caused the official seal of this Commission to be affixed at the Capitol, in the City of Phoenix, this 23rd day of April, 2015.

JODI JERICH
EXECUTIVE DIRECTOR

DISSENT: _____

DISSENT: _____

SMO:GB:sms/BES

Decision No. 75033

SERVICE LIST FOR: UNS Energy Corporation
DOCKET NOS. E-04230A-14-0011 & E-01933A-14-0011

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Attachment A

Code of Conduct

UNS Energy Corporation

and

Regulated Utilities

October 2014

Decision No. 75033

I. Purpose.

The purpose of this Code of Conduct is to govern the transactions between and among UNS Energy, the Regulated Utilities and their Affiliates. The Code of Conduct sets forth the procedures for managing intercompany transactions, including procedures for valuing and allocating intercompany transactions related to the transfer of assets and to the provision of goods and services between and among UNS Energy, the Regulated Utilities and their Affiliates. This Code of Conduct and related Policies and Procedures are intended to implement Conditions 6 and 58 of the Settlement Agreement approved by Decision No. 74689 (August 12, 2014). The Code of Conduct is not intended to supersede the obligations of UNS Energy or its Affiliates under Arizona statutes and/or the Commission's rules, regulations and orders.

II. Definitions.

"Affiliate" means a separate legal entity that is controlled by, controls, or is under common control with a Regulated Utility.

"Assets" means real property, depreciable personal property and intangible property.

"Commission" means the Arizona Corporation Commission.

"Confidential Customer Information" means any non-public customer specific information obtained by a Regulated Utility as a result of providing regulated services to the customer.

"Depreciable personal property" means vehicles, machinery, furniture, fixtures not attached to land, equipment, computer hardware and related software applications and any other tangible property, which are not goods or real property.

"Depreciated Cost" means the Fully Allocated Cost of an asset less appropriate depreciation.

"Fully Allocated Costs" means the sum of direct costs plus an appropriate share of indirect costs.

"Goods" means non-depreciable personal property, such as inventory, materials and supplies.

"Intangible property" means any asset having no physical existence, its value being set by the rights and anticipated benefits that an owner obtains by possessing it.

"Policies and Procedures" means those policies and procedures developed by UNS Energy and the Regulated Utilities to implement this Code of Conduct.

"Regulated Utilities" means TEP, UNS Electric, and UNS Gas (individually "Regulated Utility").

"TEP" means Tucson Electric Power Company as it currently exists, as its name may be changed, or as any successor enterprise.

"UNS Electric" means UNS Electric, Inc. as it currently exists, as its name may be changed, or as any successor enterprise.

"UNS Energy" means UNS Energy Corporation as it currently exists, as its name may be changed, or as any successor enterprise.

"UNS Gas" means UNS Gas, Inc. as it currently exists, as its name may be changed, or as any successor enterprise.

III. Applicability of Code of Conduct.

The Code of Conduct applies to UNS Energy and its interactions with Affiliates and the Regulated Utilities and their interactions with Affiliates.

All employees and authorized agents of UNS Energy and the Regulated Utilities shall comply with this Code of Conduct. Failure to comply with this Code of Conduct will subject the employee to disciplinary actions as described in Section VII.

IV. Affiliate Transactions.

A. Transfer of Assets between Affiliates.

1. All transfers of assets between the Regulated Utilities shall be at Depreciated Cost.

2. All transfers of assets from the Regulated Utilities to their Affiliates (other than Regulated Utilities) shall be at the higher of Depreciated Cost or fair market value.

3. All transfers of assets to the Regulated Utilities from their Affiliates (other than Regulated Utilities) shall be at the lower of Depreciated Cost or fair market value.

B. Transfer of Goods and Services between Affiliates.

1. The Regulated Utilities' tariffed goods and services shall be provided to their Affiliates and third parties at the rates and under the terms and conditions set forth in the tariff.

2. All transfers of non-tariffed goods and services between the Regulated Utilities shall be at Fully Allocated Costs.

3. All transfers of non-tariffed goods and services from the Regulated Utilities to their Affiliates (other than Regulated Utilities) shall be at the higher of Fully Allocated Costs or fair market value.

4. All transfers of goods and services to the Regulated Utilities from their Affiliates (other than Regulated Utilities) shall be at the lower of Fully Allocated Costs or fair market value.

V. Accounting for and Allocation of Costs between Affiliates.

A. UNS Energy and the Regulated Utilities shall account for and allocate costs in compliance with the Policies and Procedures attached hereto as Exhibit B.

B. UNS Energy and the Regulated Utilities may not make and implement any material change to the Policies and Procedures without seeking the prior approval of the Commission. Once notification is made of an intended modification, if no action is taken by the Commission within 30 days of its filing, the modification shall be deemed approved.

VI. Use of Customer Information.

The Regulated Utilities shall not provide Confidential Customer Information to any Affiliate or third party except in compliance with applicable Commission rules, regulations or orders.

VII. Dissemination, Education, and Compliance.

A. Copies of this Code of Conduct shall be provided to employees of UNS Energy and the Regulated Utilities, and those authorized agents of UNS Energy and the Regulated Utilities. A copy of the Code of Conduct shall be maintained on UNS Energy's Intranet.

B. Training on the provisions of the Code of Conduct and its implementation shall be provided to all employees of UNS Energy and the Regulated Utilities.

C. Compliance with the Code of Conduct is mandatory. An employee's or agent's failure or refusal to abide by or to act according to such standards may subject the employee or agent to disciplinary action, up to and including discharge from employment or termination of the agent's relationship with UNS Energy and the Regulated Utilities.

D. Questions regarding this Code of Conduct should be directed to the UNS Energy Legal Department.

VIII. Procedure to Modify the Code of Conduct.

UNS Energy, the Regulated Utilities or Commission Staff may request modifications to the Code of Conduct by filing an application with the Commission. The application shall set forth the proposed modifications and the reasons supporting them.

Attachment B

UNS Energy Corporation

Code of Conduct Policies and Procedures

October 2014

Background

UNS Energy Corporation ("UNS Energy")[1] is a wholly-owned subsidiary of Fortis, Inc. UNS Energy provides regulated electric utility and natural gas distribution service, and conducts non-regulated energy-related business activities through a number of affiliated entities. See **Exhibit 1** (the entities identified in Exhibit 1 are referred to as the "UNS System"). Tucson Electric Power Company ("TEP") provides retail electric service to customers in Pima and Cochise Counties, and wholesale power to other utilities and power marketers. UniSource Energy Services ("UES") provides retail electric service through UNS Electric, Inc. to customers in Mohave and Santa Cruz Counties, and local natural gas distribution service through UNS Gas, Inc. to customers located across Northern Arizona and in Santa Cruz County. The regulated utility operations of TEP, UNS Electric, Inc. and UNS Gas, Inc. (the "Regulated Utilities") are subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC") and the Arizona Corporation Commission ("Commission" or "ACC").

The Regulated Utilities incur costs, both capital and operating, in connection with the provision of administrative support and other services to their electric and gas utility and non-utility business activities (to the extent offered), as well as to Affiliates. It is, therefore, necessary to develop, implement, and effectively administer an adequate and effective cost

[1] Capitalized terms not otherwise defined in these Policies and Procedures have the same definitions as set forth in the Code of Conduct.

allocation policy. The principal objectives of the intra-and inter-company cost allocation procedures are to:

- Prevent or minimize, to the extent practical, the potential for cross-subsidization of one activity or entity by another, and
- Achieve a proper balance between the desired precision of the cost allocation process with the cost of attaining such accuracy.

Rates charged for regulated energy utility service provided by the Regulated Utilities will be based solely on the reasonable and necessary costs incurred in connection with the provision of safe, reliable service to customers. Because the Regulated Utilities routinely incur administrative and other costs that benefit regulated and non-regulated operations and Affiliates, an appropriate cost allocation methodology is required. The cost assignment and allocation methodology described herein provides for the equitable assignment and allocation of costs to businesses, activities, and Affiliates, and prevents cross-subsidization.

The code of conduct and these cost allocation policies and procedures are intended to produce reasonable results that are consistent with applicable Arizona law, the reporting requirements of the Securities and Exchange Commission and FERC, and the Internal Revenue Code.

Cost Accounting Principles

As a general principal, UNS Energy and the Regulated Utilities support the use of an equitable, fully-distributed costing methodology for assigning costs between regulated and non-regulated business activities and between Affiliates, with emphasis on direct assignment and cost causation to the extent possible. The overriding goals of the cost accounting and

allocation process are to limit the possibility of cross-subsidization of any entity or activity by another, and to achieve the desired objectives as best as practicable.

Presently, most UNS System corporate services in Arizona (i.e. accounting, information systems, etc.) are performed by TEP, as needed by its regulated electric utility and its non-utility business activities, as well as by its other Affiliates located in Arizona. The objectives and procedures described herein, however, would apply equally to the extent that Affiliates of the UNS System provide services to TEP or other Affiliates.

Costs should be directly assigned to the benefiting activity or entity to the extent possible. Costs benefiting multiple activities or entities that cannot be directly assigned will be considered as common costs, and accumulated in homogeneous cost pools. Where possible, common costs should be allocated to the beneficiaries on the basis of causal relationships, identified by determining the factor which gives rise to the incurrence of the cost. Common costs for which a specifically identifiable causal relationship cannot be established should be allocated on a residual basis using the allocation methodology described later herein.

Utility Plant in Service and other fixed assets that benefit both regulated and non-regulated activities or Affiliates are considered in the cost allocation process through the inclusion of a return on the net investment, computed using the current authorized regulated rate of return. For this purpose, the net investment represents the gross original fixed asset cost less accumulated depreciation and related accumulated deferred income taxes.

Direct Costing

All incurred costs that directly and solely benefit a specific business activity or Affiliate are charged directly to the beneficiary. Costs may be directly assignable to: construction activities, utility operations, non-utility operations, or the business of other Affiliates in the UNS System. Directly assignable costs include such items as payroll and payroll related overhead costs, as well as identifiable non-labor costs. Employees are required to directly charge their time and expenses that they may identify as directly assignable in accordance with this reporting policy.

For accounting and billing purposes, directly assignable costs will be handled as follows:

- Basic payroll costs of both operating and administrative employees, and related payroll taxes, will be charged as follows:
  - Labor costs applicable to construction will be charged to the appropriate work order.
  - Labor costs applicable to non-utility operations will be charged to the appropriate below-the-line account.
  - Labor costs chargeable to Affiliates will be charged to the appropriate inter-company receivable account.
- Employee benefits and other costs relating to directly assignable labor costs will be charged to the same work orders, below-the-line accounts, or inter-company receivable to which such labor was charged.
- Directly assignable non-labor costs shall be charged to the appropriate work order, below-the-line accounts, or inter-company receivable account.

Fixed Labor Cost Distributions

Vice Presidents, Senior Vice Presidents, and the President of UNS Energy and of TEP will account for their time on an "exception" time basis. In connection therewith, each of the affected officers will use the same payroll cost account distribution (intra- and inter-company) percentages for all payroll periods throughout the year, unless there is a significant change in the individual's responsibilities or activities, at which time the distribution factors would be revised. To arrive at the respective fixed payroll allocation factors, an annual time study is prepared for the purpose of identifying the normal, recurring activities of each affected employee and the benefiting entities, with percentages derived therefrom being the basis for future fixed payroll cost assignment.

Allocated Costs

Incurred costs that cannot be directly assigned, but which benefit multiple activities and entities, both regulated and non-regulated, will be assigned to homogeneous cost pools for allocation. Where a sufficient degree of correlation can be reasonably identified, such allocations will be based on factors representing elements of cost causation. Detailed procedures for specific allocations by the Regulated Utilities based on cost causative factors shall be maintained by the Regulated Utilities and provided to the Commission upon request.

Where elements of cost causation cannot be reasonably or economically identified as the basis for cost allocation, a residual allocator will be applied to the allocation pool. The residual allocator used by members of the UNS System is a three-factor allocation methodology based on a weighted average of annual revenues, payroll costs, and plant

investment. It is widely-used and has been accepted by the FERC and state regulatory commissions.

General Office Buildings

Administrative and general corporate activities benefiting TEP and other members of the UNS System are performed by TEP employees located at the UNS Energy Headquarters Building ("HQ") and in the Operating Headquarters Building ("OH") and other facilities located at the Sundt Generating Station that are owned by TEP.

Since TEP's regulated and non-regulated operations and other UNS System Affiliates benefit from such services, there needs to be an accurate and equitable allocation of the capital and operating costs being incurred to the benefiting activities and entities. A key element of the cost allocation process is to equitably assign an appropriate portion of the capital and operating costs applicable to the general office buildings to benefiting activities and Affiliates. The allocation of building costs will be made via a per employee hourly payroll loading charge, based on an annual revenue requirement.

Fair Market Value

In transactions potentially requiring the determination of a fair market value, the Regulated Utilities shall act in a commercially reasonable and prudent manner in determining the fair market value of an asset, good or service, to the extent practicable, given the specific circumstances of the transaction.

Tariffed Services

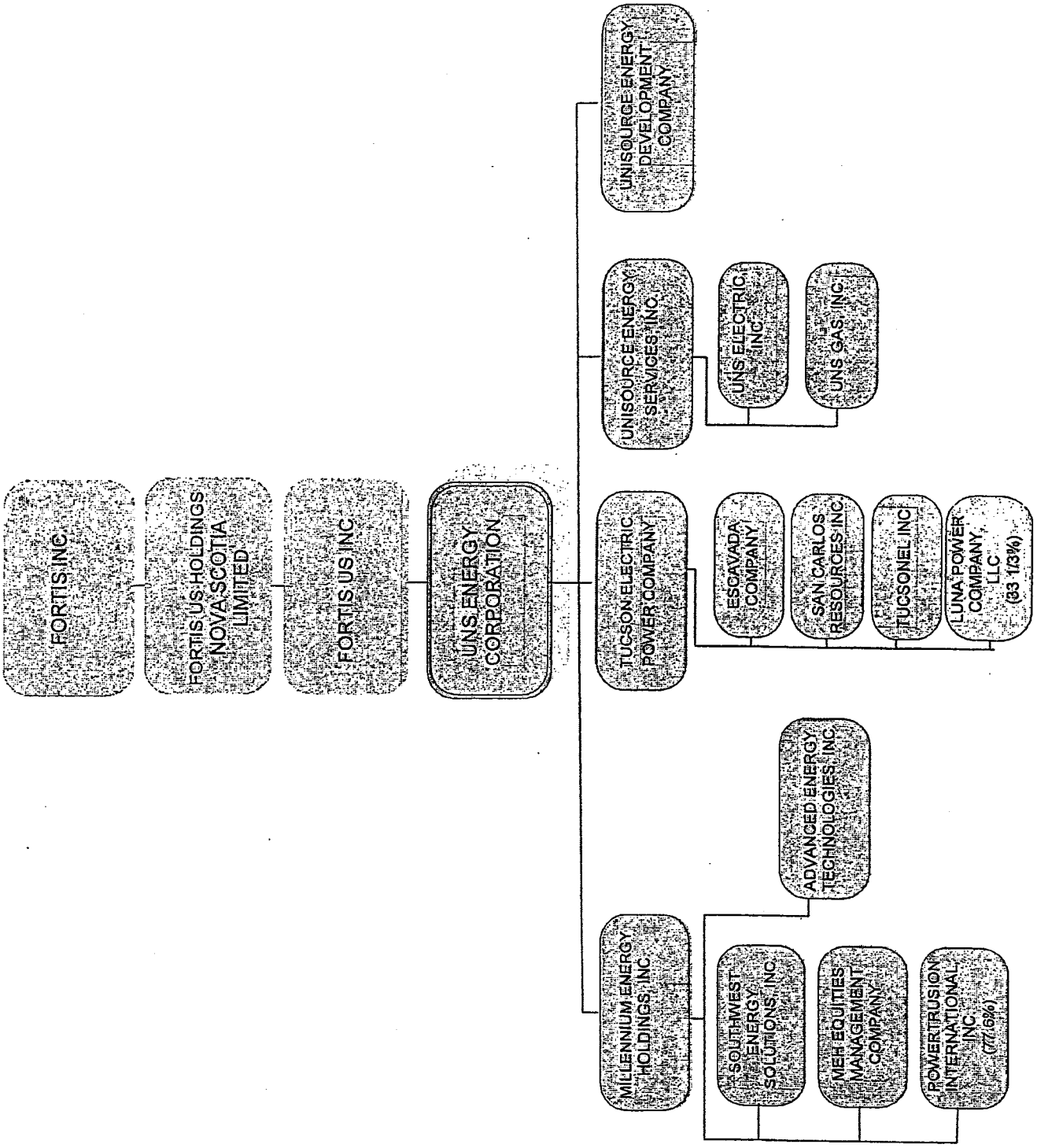
Regulated utility services provided by any Regulated Utility will be priced at the existing tariffed rate for that service.

Revisions and Updating

These policies and code of conduct will be updated as necessary in the event of major changes in operations or regulatory conditions such as retail competition.

Exhibit 1

UNS System



Decision No. 75033

Rebuttal Testimony of

David J. Lewis

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

Rebuttal Testimony of

David J. Lewis

on Behalf of

Tucson Electric Power Company

July 25, 2016

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Exhibits

Exhibit DJL-R-1	Comparison of Adjustments to Revenue Requirement
Exhibit DJL-R-2	Correction of RUCO Adjustments
Exhibit DJL-R-3	Correction of Staff Adjustments
Exhibit DJL-R-4	Response to RUCO 11.02
Exhibit DJL-R-5	Post-Test Year Projects
Exhibit DJL-R-6	Staff Response to TEP 2.1

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is David J. Lewis and my business address is 88 East Broadway Blvd., Tucson, Arizona 85701.

Q. Did you file Direct Testimony in this proceeding?

A. No.

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. My Rebuttal Testimony is filed on behalf of Tucson Electric Power Company ("TEP" or "Company").

Q. What is your position with TEP?

A. I am the Manager of Revenue Requirements for UNS Energy Corporation ("UNS Energy"), an indirect, wholly owned subsidiary of Fortis Inc. ("Fortis"). I am responsible for monitoring and determining revenue requirements for all the regulated subsidiaries of UNS Energy, including TEP.

Q. Please describe your education and experience.

A. I hold a Bachelor of Science in Business Administration, a Master's of Business Administration and a Master's of Science in Accountancy. I have over 13 years' experience within the utility industry.

Prior to working for UNS Energy, I was employed by Green Valley Water Company as the principal accountant reporting directly to the Controller.

Before then, I was the business support analysis for Raytheon Missile Systems NAPI facility in Farmington, New Mexico.

Q. Which Commission Staff and/or Intervenor testimony do you address in your Rebuttal Testimony?

A. I address certain adjustments that Staff witnesses Donna Mullinax, Roxie McCullar and Michael McGarry recommend in their Direct Testimonies. I also address adjustments that Residential Utility Consumer Office ("RUCO") witnesses Jeffrey Michlik and Frank Radigan proposes in their Direct Testimonies. Any inadvertent omission of discussion of any adjustment should not be considered an acceptance of the position or recommendation.

Q. What else do you address in your Testimony?

A. I am providing an exhibit (**Exhibit DJL-R-1**) that summarizes adjustments that the Company is making in its Rebuttal Testimony.

II. COMPUTATION CORRECTIONS TO STAFF'S AND RUCO'S DIRECT FILINGS.

Q. Are there computation errors that you have identified within Staff's or RUCO's Adjustments?

A. Yes. I have provided an attachment, **Exhibit DJL-R-2 and Exhibit DJL-R-3,** which summarizes and explains the errors that I have identified and sets forth the corrected adjustments.

Q. What computation errors did you identify?

A. As explained in **Exhibit DJL-R-2 and Exhibit DJL-R-3**, the following errors were identified.

1. Correction of Staff's adjustment E-5 Cash Working Capital. Staff inadvertently used the ACC Jurisdictional factor twice in its calculation.
2. Staff did not adjust Accumulated Deferred Income Taxes to reflect proposed changes to Rate Base.
3. Correction of Staff's adjustment E-6 Depreciation Expense. Staff's methodology to adjust Accumulated Depreciation is incorrect. The Average Remaining Life depreciation technique used in the current depreciation study. It is a self-correcting approach in that its continued application constantly trues up the proposed depreciation rates over the average remaining life of the property to assure full recovery of the total asset cost. Therefore, Staff does not need to adjust accumulated reserve as proposed. Reducing the reserve balance overstates the asset value on which the Company is earning a return.
4. Correction to RUCO's adjustment JMM-22 Overhaul and Outage. During the discovery process, the Company identified a formula error that understated the amount of test year outage expense. RUCO's adjustment used the revised outage expense amounts; however, RUCO's intent was to adjust test year outage expense to a normalized amount of $8,127,571. The adjustment however reduced the filed outage amount proposed by the Company to $7,165,217. RUCO should have started with the Company's filed position, not the revised position since the revised amount was not reflected in the original revenue requirement they are adjusting from.
5. Correction to RUCO's adjustment JMM-24. The Accrual rates used in RUCO's post-test year adjustment do not reflect what TEP is currently requesting. The Company's post-test year pro-forma adjustment calculated ACC jurisdictional depreciation of $4,137,853. RUCO's pro-forma adjustment removes $7,870,808, which is roughly 60% more than the Company's filed position. This is because most of the accrual rates used by RUCO were twice that of what

the Company proposed. RUCO's pro-forma methodology removed twelve months of depreciation expense from test year expense for both post-test year plant and post-test year plant renewables. This is incorrect as explained in the Company's response to RUCO's data request RUCO 11.2 (attached as **Exhibit DJL-R-4**).

6. RUCO did not adjust Accumulated Deferred Income Taxes to reflect proposed changes to Rate Base.

7. Correction to RUCO's JMM-22 Overhaul and Outage. RUCO did not adjust the frequency percent to reflect a levelized average over the 2005 through 2015 period. RUCO intended to calculate a levelized average spread over 11 years instead of 17 years as reflected in their actual adjustment. This error occurred because RUCO did not correct the frequency formula, instead they used what was being calculated in the original pro-forma. Had RUCO corrected the formula, RUCO's revised Overhaul and Outage expense would have been approximately $13.1 million, not the $8.1 million presented in JMM-22.

III. REBUTTAL TO RATE BASE ADJUSTMENTS.

A. Post-Test Year Plant.

Q. Did Staff or RUCO make any adjustments to the Post-Test Year rate base amounts requested by the Company?

A. Yes, Staff witness Donna Mullinax removed 16 post-test year plant projects, 14 regular projects[1] and three renewable energy projects[2]. This adjustment reduces ACC

[1] Staff Adjustment E-1, Mullinax Direct Revenue Requirement Testimony, Table 2, page 9.
[2] Staff Adjustment E-2, Mullinax Direct Revenue Requirement Testimony, Table 4, page 13.

jurisdictional original cost rate base ("OCRB") by approximately $30.6 million.[3] RUCO witness Frank Radigan recommends the removal of all post-test year amounts proposed by the company. RUCO's adjustment reduces OCRB by approximately $80 million.

Q. Do you agree with Staff's recommendation to remove these 16 Post Test Year plant projects?

A. No, I do not. Ms. Mullinax recommends excluding post-test-year plant that was not in service within six months after the end of the test year. Her recommendation applies to regular Post Test Year Plant (Staff Adjustment E-1) and renewable Post Test Year Plant (Staff Adjustment E-2). Her reasoning is that the integrity of using a test year becomes increasingly blurred as more and more adjustments are made beyond the end of the test year period[4]. <u>However, the Company is only requesting to include the costs incurred prior to the end of the test year, and invested in plant items that will be in service and benefiting customers by the time new rates are effective. We are not asking for inclusion of any costs incurred post-test year.</u> These facilities will primarily be used to maintain service levels and system reliability and will serve existing test year customers.

Q. How much of the ACC Jurisdictional $30.6 million in Post Test Year plant removed from rate base by Staff is currently In Service?

A. The $30.6 million in Post Test Year plant is made up of $14.7 million in non-renewable projects and $15.9 million in renewable projects. For non-renewable projects, of the $14.7 million identified by Staff, approximately $13.3 million has been placed into service as of June 30, 2016. The Company expects the remaining $1.4 million to be in service by the time new rates become effective. For the renewable projects, of the $15.9 million identified by Staff, $7.2 million will be in service by August 31, 2016, and the

[3] Reduction to rate base of $15.9 million (Mullinax Direct Revenue Requirement Testimony, page 13, line 12) and $14.7 million for non-renewable plant (Mullinax Direct Revenue Requirement, page 9, line 8.
[4] Mullinax Direct Revenue Requirement Testimony, page 10, line 3 through 6.

remaining $8.7 million will be in service prior to new rates becoming effective. A list showing the current status of each of these 16 projects is attached as **Exhibit DJL-R-5**.

Q. Has the Commission allowed the use of Post-Test-Year Plant before?

A. Yes. The Commission approved including Post-Test-Year Plant for UNS Electric in the 2013 UNS Electric Rate Order. The Commission has also allowed Post-Test-Year Plant in numerous other cases, including: EPCOR Water Arizona, Inc., in Decision No. 75268 (December 31, 2015); Chaparral City Water Company, Decision No. 74568 (June 20, 2014); TEP in Decision No. 73912 (June 27, 2013); Arizona Public Service Company ("APS") in Decision No. 73183 (May 24, 2012), Rio Rico Utilities, Inc., in Decision No. 67279 (October 5, 2004); Arizona Water Co., in Decision No. 66849 (March 19, 2004); and Bella Vista Water Co., Inc., in Decision No. 65350 (November 1, 2002). Staff's response to TEP Data Request 2.1 shows that the Commission has not limited Post-Test Year Plant to 6 months and has approved longer periods in a number of cases. A copy of this response is attached as **Exhibit DJL-R-6**.

Q. Do you agree with RUCO's recommendation to remove all of Post-Test Year plant proposed by the Company?

A. No. As noted above, the Commission on several occasions has allowed companies to include Post-Test Year plant in rate base. Mr. Radigan believes the Company's request for post-test year plant recovery in rates requires a detailed presentation that the large and continuous build out of infrastructure reflects appropriate, efficient, effective, and timely decision-making.[5] As stated in Company witness Mr. Hutchens rebuttal testimony, as part of the Company's last rate case, TEP agreed to meet annually with Staff to review the Company's actual capital spending and future plans for the upcoming year. The point of these meeting is to create a free exchange of information of what the company needs in

[5] Radigan Direct Revenue Requirement Testimony, page 29, lines 9 through 13

order to maintain and improve system reliability and effective service. Mr. Radigan's argument is without merit and should not be considered.

B. <u>Sundt Coal Handling Facilities.</u>

Q. Did Staff or RUCO make and adjustment for Sundt Coal Handling Facilities?

A. Yes, Staff accepted the Company's ACC jurisdictional allocation correction to original filing. This adjustment increased jurisdictional rate base by $20,000.

C. <u>Sundt and San Juan Unit 2 Materials and Supplies.</u>

Q. Please explain the update to the Sundt Coal Handling Facility Materials and Supplies pro-forma adjustment.

A. Company witness Frank Marino is supporting this adjustment. The Revised adjustment increase rate base by $731,117 and reduces operating income by $243,706.

IV. <u>REBUTTAL TO OPERATING INCOME ADJUSTMENTS.</u>

A. <u>TEP Proposed Depreciation Rates</u>.

Q. Did Staff or RUCO adjust the proposed accrual rates as outlined in the 2015 Depreciation Study?

A. Yes. Staff witness Ms. McCullar recommends: a -5 percent future net salvage percent for Distribution plant; a final retirement year of 2032 for Sundt Steam Units 1 and 2; North Loop CT Units 1, 2, and 3; and Sundt CT Units 1 and 2; and the estimated dismantlement costs be set at current dollars instead of an estimated future dismantlement costs. I will address the recommended -5 percent future net salvage percent and the dismantlement

cost set at current dollars. Company witness Michael Sheehan will address the final year retirement dates proposed by Staff.

Q. Do you agree with Staff's proposal that dismantlement cost be set at current dollars?

A. No. Ms. McCullar believes it is inappropriate to charge ratepayers now for the estimated dismantlement cost in future dollars at the time of retirement, and instead proposes to estimate dismantlement costs in current dollars. This proposal is inappropriate and does not incorporate all the factors that should be considered in ratemaking, particularly the equitable treatment of different generation of customers. After accruing for terminal net salvage in current dollars, TEP will have to capitalize net cost of dismantlement in future years (when the facility is no longer providing service) to be recovered by future customers and not by the customers presently receiving service from these assets. Ms. McCullar proposal is designed to reduce rates for today's customers but to do so at the expense of tomorrow's customers. In addition, Ms. McCullar's approach ignores the reality of inflation; these future retirement costs will not be paid in current dollars, but rather in inflated future dollars at the time of retirement.

Q. Is it appropriate to ask current customers to pay for future costs of plant removal?

A. Yes, the future cost to remove plant is part of the service value that it renders to current customers, and a portion of those costs should be recovered from current customers. As future costs are recovered from current customers, they are deducted from rate base. Thus, current customers receive a benefit as they pay their fair, ratable portion of those costs.

Q. Do you agree with Staff's position to set net salvage for Distribution Plant at -5 percent?

A. Yes. The -5 percent future net salvage represents the 25 year historic average; therefore, using -5 percent for net salvage is appropriate.

Q. What do you recommend for Dismantlement costs and net salvage for Distribution Plant?

A. While TEP strongly believes that the requested Accrual rates provided in the 2015 Depreciation study should be approved, the Company will accept Mrs. McCullar recommendation of -5 percent future net salvage for distribution plant and dismantlement costs be set a current dollars in this proceeding. However, in the Company's opinion it is just pushing today's "cost to serve" to future customers.

B. <u>Overhaul and Outage Adjustment</u>.

Q. Did Staff or RUCO make an adjustment for Overhaul and Outage expense?

A. Yes, Staff witness McGarry, used a four-year period (2012 through 2015) to reflect the typical methodology to normalized expense between base rate cases. RUCO witness Michlik uses an historical average from 2005 to 2015 to reflect overhaul and outage expenses.

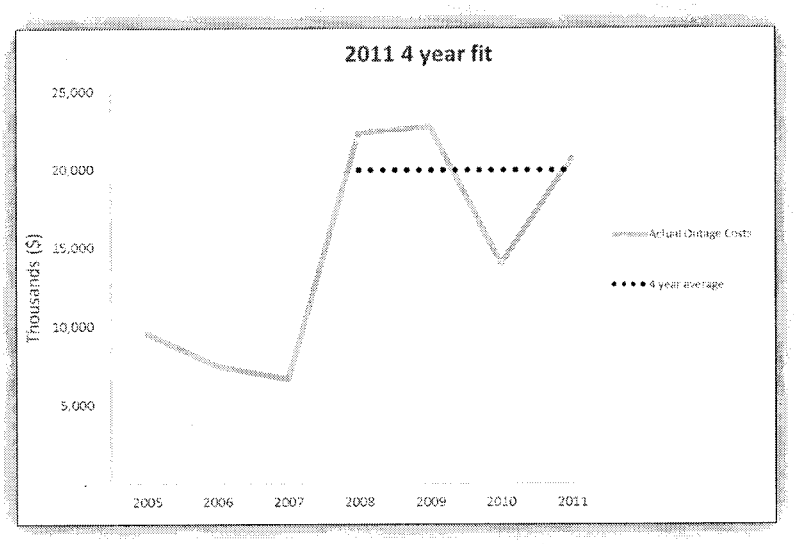
Q. Do you agree with either Staff or RUCO's adjustment?

A. No. First I will address my concerns with Mr. Michlik's adjustment. Ignoring the mathematical error explained earlier in my testimony, the Company strongly opposes Mr. Michlik's exclusion of outage expense related to Gila River Unit 3. As explained in greater detail by TEP witness Mr. Sheehan these outage costs are not represented in the calculation proposed by Mr. Michlik. In the most recent UNS Electric case, Mr. Michlik

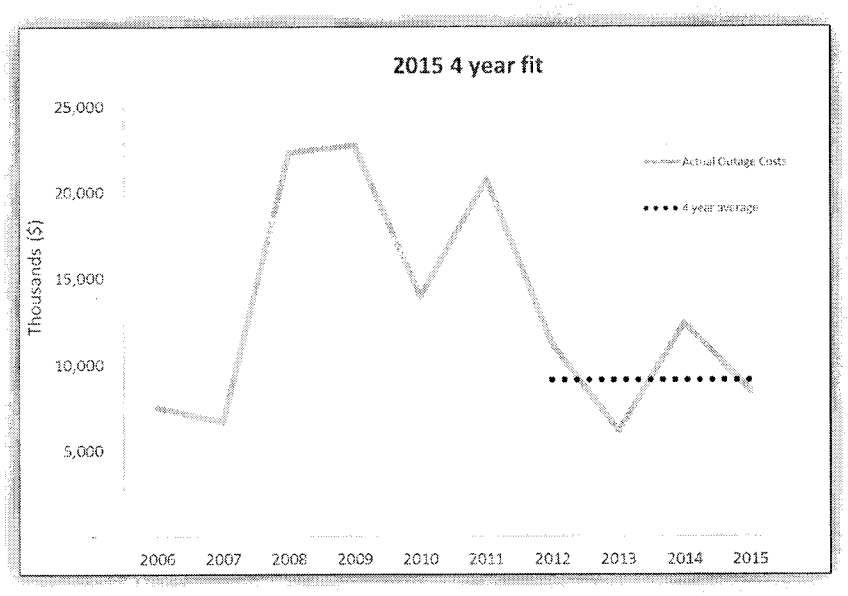
did not oppose recovery of the 25% ownership share of outage expense to be recovered in UNS Electric's base rates therefore, the Company does not understand his rationale to exclude TEP's share of these same outage costs from TEP's base rates.

By appropriately including Gila River Unit 3 and correcting for the calculation error; RUCO's levelized overhaul and outage expense would be $14.6 million. This is roughly the same as the company's revised position.

Staff witness McGarry methodology to "normalize expense" over a four year period significantly under recovers the actual levelized outage costs. As part of the 2013 TEP Settlement Agreement, the Company accepted Staff's ACC jurisdictional outage expense of $11.6 million to be recovered through base rates. This adjustment was based on actual historical costs for the period 2004 to 2011. Mr. McGarry's proposal to use just a four-year period will reduce outage costs to roughly $9.1 million. Had the Company used McGarry's four year average methodology in the last rate case, the outage expense would have been roughly $19 million. It seems that Staff's methodologies are changing significantly between rate cases with no recognition of the reality of the timing of outages. Generation overhauls are quite costly and do not occur at regular annual intervals. In general, minor overhauls are performed every 1 to 3 years and major overhauls are performed every 5 to 8 years. Thus, a 4 year normalization will completely miss the cost of major overhauls in some test years, while the normalized cost would shoot up if the major overhaul falls within the 4 year window. To use such a short normalization period will lead to extreme volatility in the normalized levels as depicted on the following tables:



*The chart above depicts higher averages cost in years where there are major outages.



*The chart above depicts lower average cost in years where there are no major outages.

As can be seen by these two graphs using a simple four year average creates huge swings in levelized outage expense. These swings are attributable to major outages that do not occur consistently in such short duration periods. Had McGarry used a 10 year historical

average, the result would have been similar to the requested amount proposed by the Company in its original filing.

C. **Rate Case Expense.**

Q. Did Staff or RUCO dispute the Company's pro forma rate case expense?

A. Yes, Staff recommends rate case expense of $900,000 normalized over four years. RUCO recommends a rate case expense of $950,000 normalized over three years.

Q. Do you agree with Staff and RUCO's recommendation?

A. No. Rate cases are complicated proceedings involving outside counsel and consultants. There are also costs for mailing and publishing notice. There is a significant amount of discovery that takes place. In addition to the application, there are three rounds of testimony prepared by the Company. There is a hearing and then post-hearing briefing, exceptions and open meeting. TEP believes that it is handling its rate cases in the most cost efficient manner possible as shown by its use of numerous internal personal for witnesses and rate case costs. TEP should be compensated for its actual costs.

Q. Do you have any other comments on this issue?

A. Yes. TEP's rate case involves 26 Interveners and 47 witnesses, and the Company has responded to over 3,000 data request. TEP incurred over $1 million in rate case expense in support of its 2012/2013 rate case even though that case ended in a settlement between the parties. UNS Electric is currently in a fully litigated rate case and has incurred over $1 million in rate case expense. Notably, the hearing in that case ran for a full 15 days, even though there revenue requirement issues were largely resolved prior to the hearing. Here, the hearing will likely be longer given the increased number of parties and witnesses, as well as the fact that there are numerous revenue requirement disputes in

addition to the rate design disputes addressed in the UNS Electric case. TEP's request to recover $1.2 million in this proceeding reflects the increasing complexity of rate cases in Arizona.

D Long Term Incentive Compensation.

Q. Please explain the update to the Long Term Incentive Compensation pro-forma adjustment.

A. Company witness Frank Marino is supporting this adjustment. The revised adjustment increase operating income by $880,967.

E Lime Costs.

Q. Please explain the Lime Cost pro-forma adjustment.

A. This adjustment removes all of the Lime Cost associated with our jointly owned coal-fired generating facilities from non-fuel operating cost presently recovered through base rates and moves them to be recovered in the base cost of fuel. This is the same methodology that was approved in 2013 TEP Settlement Agreement which allowed TEP to recover lime expense associated with the Springerville generating station as a variable cost tied to fuel consumption and reconciled through the PPFAC (See settlement agreement section 6.2). This section clearly states that, lime cost associated with fuel consumption are to be recovered as a fuel cost for all of TEP's generation facilities. During the Company's last rate case proceeding, only the cost of lime associated with Springerville was available and, as a result, was the only amount removed from non-fuel operating cost in the "cost of service" as part of the 2013 TEP Settlement Agreement. As such, the lime cost for the Companies other coal-fired generating facilities remained a part of non-fuel costs. We propose to treat the lime costs at all coal-fired generating

plants in a consistent manner to more accurately classifies and recover fuel-related costs through base cost of fuel rather than non-fuel rates.

Q. Why did TEP not make this adjustment in its direct filing?

A. It was an oversight not to include all lime costs incurred at all TEP's coal-fired generating facilities in the base fuel cost in the Company's initial filing. By moving the lime costs from the non-fuel component of base rates, this adjustment has a zero net impact to the cost of service.

F <u>Transmission Expense.</u>

Q. Please explain why the Transmission Expense increase operating income by $1.7 million in the Company's filed Rebuttal?

A. Sure, Transmission costs are recovered through base rates which reflect the transmission costs associated with serving retail customers. As a result of the Company reducing its annualized retail sales to reflect the curtailment of our largest customer's sight usage. This adjustment reduces the expected transmission costs in concurrence with the reduction in transmission revenues included in the adjusted test year revenues.

V. CONCLUSION.

Q. What is the Company's recommendation for revenue requirement?

A. TEP is requesting a revised increase in non-fuel base rates revenues of $100.6 million, or approximately 11 percent over adjusted retail electric revenues at current rates of $909.325 million.

Q. Does this conclude your Testimony?

A. Yes, it does.

Exhibit DJL – R – 1

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
EXHIBIT 1

	TEP As Filed	ACC As Filed	RUCO As Filed	TEP Revised	TEP Difference	Explanation of TEP Revisions
Original Cost Rate Base - Unadjusted	$2,108,583,243	$2,108,583,243	$2,108,583,243	$2,108,583,243	-	
Rate Base Adjustments						
Jurisdictional Allocation (Demand and Energy)	-	-	(138,422,327)	(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)	(41,966,722)	(41,966,722)	(41,239,083)	727,640	Impact of change to jurisdictional allocations
Fortis Merger Rate Base Adjustment	(522,398)	(522,398)	(522,398)	(517,560)	4,838	Impact of change to jurisdictional allocations
Asset Retirement Obligation	-	-	-	-	-	
Post Test Year Plant	51,782,029	37,124,629	-	51,003,979	(778,051)	Impact of change to jurisdictional allocations
Post Test Year Plant - Renewables	20,794,266	4,872,919	-	20,433,724	(360,541)	Impact of change to jurisdictional allocations
Delayed Unitization	13,237,543	13,237,543	13,237,543	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	30,341,626	-	
Accumulated Deferred Income Taxes	(58,308,686)	(58,303,521)	(58,308,686)	(57,662,694)	645,992	Impact of change to jurisdictional allocations
ADIT - Extension of Bonus Depreciation	-	(12,814,172)	-	(12,672,205)	(12,672,205)	ADIT related to extension of bonus depreciation
San Juan Unit 2	-	-	-	(0)	(0)	
Sundt Coal Handling facilities	(19,120)	880	(19,120)	(18,789)	332	Impact of change to jurisdictional allocations
SGS Unit 1 Lease Equity (related to 14.1% acquisition in 2006)	6,855,471	6,855,471	6,855,471	6,736,607	(118,864)	Impact of change to jurisdictional allocations
Sundt & San Juan M&S	1,225,594	1,225,594	1,225,594	1,956,711	731,117	Increase is do to the revision of obsolete inventory at Sundt
Head Quarters	-	-	(55,043,003)	-	-	
Working Capital	(27,325,154)	(19,387,724)	(25,313,900)	(20,740,139)	6,585,016	Impact of changes to pro forma adjustments including $160K in jurisdictional allocation
Accumulated Depreciation adj and LTI	-	9,020,000	-	-	-	
Total Adjustments	(3,905,553)	(30,315,876)	(267,935,924)	(42,256,127)	(38,350,574)	
Pro Forma OCRB	2,104,677,690	2,078,267,367	1,840,647,319	2,066,327,116	(38,350,574)	

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
EXHIBIT 1

	TEP As Filed	ACC As Filed	RUCO As Filed	TEP Revised	TEP Difference	Explanation of TEP Revisions
Proposed Rate of Return	7.34%	6.68%	6.76%	7.16%		
Required Operating Income OCRB	$154,416,180	$138,763,150	$124,427,759	$147,984,232	(6,431,948)	
Fair Value Increment of Rate Base	$808,601,055	$808,600,679	$741,672,017	791,549,067	(17,051,988)	
Fair Value Rate Base (FVRB)	$2,913,278,745	$2,886,869,000	$2,582,319,188	$2,857,876,183	(55,402,562)	
Proposed FVROR	5.69%	5.00%	5.20%	5.57%		
Required Operating Income on FVRB	165,898,315	144,418,355	134,398,160	159,224,227	(6,674,088)	
Implied ROR on Fair Value Increment of Rate Base	1.42%	0.70%	1.34%	1.42%		
Original Operating Income - Unadjusted	$318,271,141	$318,271,141	$318,271,141	$318,271,141		
Operating Income Adjustments						
Operating Revenue Adjustments						
Lost Fixed Cost Revenue	(10,719,946)	(10,719,946)	(10,719,946)	(10,719,946)	-	
Environmental Cost Adjustor	(1,260,631)	(1,260,631)	(1,260,631)	(1,260,631)	-	
REST and DSM	(48,370,058)	(48,370,058)	(48,370,058)	(48,370,058)	-	
Non-Retail & Non Recurring Revenue	(112,150)	(112,150)	(112,150)	(112,150)	-	
Springerville Units 3 & 4	(111,813,089)	(111,813,089)	(111,813,089)	(111,813,089)	-	
Power Supply Management	(1,099,586)	(1,099,586)	(1,099,586)	(1,099,586)	-	
Customer, Weather and Recalculation of Unbilled Revenue	(4,791,733)	(4,791,733)	(3,956,411)	(4,791,733)	-	
Base Cost of Fuel & Purchased Power	(17,815,595)	(17,815,595)	(17,815,595)	(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).

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
EXHIBIT 1

	TEP As Filed	ACC As Filed	RUCO As Filed	TEP Revised	TEP Difference	Explanation of TEP Revisions
Miscellaneous Service Revenue	284,370	284,370	284,370	284,370	-	
TEP Headquarters - Retail Space	250,000	250,000	250,000	250,000	-	
Total Adjustments to Operating Revenues	(195,448,418)	(195,448,418)	(194,613,096)	(210,226,864)	(14,778,446)	
Operating Expense Adjustments						
Jurisdictional Allocation (Demand and Energy)	-	-	(19,532,187)	(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)	(19,891,996)	(19,891,996)	(19,769,956)	122,040	Impact of change to jurisdictional allocations
Non-Retail & Non Recurring Revenue	(1,696,421)	(1,696,421)	(1,696,421)	(1,663,540)	32,881	Impact of change to jurisdictional allocations
Springerville Units 3 & 4	(84,382,546)	(84,382,546)	(84,382,546)	(83,129,337)	1,253,210	Impact of change to jurisdictional allocations
Sales of SO2 Allowances	47	47	47	47	-	
Sales for Resale	(162,821,057)	(162,821,057)	(162,821,057)	(162,821,057)	-	
Power Supply Management	(278,075)	(278,075)	(278,075)	(276,646)	1,429	Impact of change to jurisdictional allocations
Base Cost of Fuel & Purchased Power	226,811,827	226,811,827	226,811,827	212,033,380	(14,778,447)	See explanation in Operating Revenues section.
Gila River O&M	6,130,964	6,130,964	6,130,964	6,024,663	(106,301)	Impact of change to jurisdictional allocations
Springerville Unit 1	(11,558,130)	(11,558,130)	(11,558,130)	(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	Addition of non-fuel operating costs associated with the 50.5% share of SGS Unit 1.
Overhaul & Outage Normalization	5,176,492	1,043,941	(870,213)	5,644,715	468,223	Increase is due to a formula error that understated the proposed outage expected and includes an offsetting jurisdictional allocation impact of ($90K).
Payroll Expense	2,264,794	1,121,186	2,264,794	2,250,757	(14,037)	Impact of change to jurisdictional allocations
Payroll Tax Expense	151,051	76,051	151,051	151,051	-	
Pension & Benefits	2,004,436	2,050,431	1,056,440	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	1,339,160	-	

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
EXHIBIT 1

	TEP As Filed	ACC As Filed	RUCO As Filed	TEP Revised	TEP Difference	Explanation of TEP Revisions
Short-Term Incentive Compensation	702,960	(2,803,734)	(2,964,033)	1,578,745	875,785	During discovery, the company inadvertently included $1,056,578 of capital cost in determining the levelized costs to FERC 920. By doing so, the amount requested was understated. The $875,785 is the result of correcting this understatement and includes an offsetting $11K due to the change in jurisdictional allocations.
Rate Case Expense	107,834	(36,208)	27,834	107,834	-	
Injuries and Damages	1,419	1,419	1,419	1,419	-	
Membership Dues	(212,696)	(212,696)	(416,963)	(212,690)	6	Impact of change to jurisdictional allocations
Bad Debt Expense	(149,199)	(149,199)	(149,199)	(149,199)	-	
San Juan Unit 2 Direct Operating Cost	(3,921,687)	(3,921,687)	(3,921,687)	(3,869,457)	52,230	Impact of change to jurisdictional allocations
Long Term Incentive Compensation	880,967	-	(639,979)	-	(880,967)	Remove long term incentive compensation as proposed by Staff.
Depr. & Amort. Expense	9,253,715	(1,665,318)	(9,202,556)	1,542,840	(7,710,875)	Decrease is due to removal of 2% inflation for dismantlement costs, and a 5% future net salvage value for distribution assets. Includes a jurisdictional allocation impact of ($201K)
Post Test Year Plant Depreciation and Amortization	-	-	-	4,568,108	4,568,108	Increase is due to $4.6M in post test year plant and renewables that was inadvertentaly excluded in the original filing.
Sundt & San Juan M&S	408,531	408,531	408,531	652,237	243,706	Increase is due to an increase in obsolete Sundt coal handling inventory.
Property Tax Expense	3,119,696	2,694,696	2,554,799	3,119,770	74	Impact of change to jurisdictional allocations
Asset Retirement Obligation	(393,590)	(393,590)	(393,590)	(386,765)	6,825	Impact of change to jurisdictional allocations
SGS Common Facilities Lease	(1,195,980)	(1,195,980)	(1,195,980)	(1,175,244)	20,736	Impact of change to jurisdictional allocations
San Juan Unit 1 SCNR O&M	955,223	955,223	955,223	938,661	(16,562)	Impact of change to jurisdictional allocations
Fortis Merger Operating Income Adjustment	(31,176,174)	(31,176,174)	(31,176,174)	(31,176,174)	-	
Lime Expense				(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	-	-	(942,257)	-	-	
Credit Card Processing Fees	3,475,500	-	-	-	(3,475,500)	Removed credit card processing fees as proposed by Staff and RUCO.

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
EXHIBIT 1

	TEP As Filed	ACC As Filed	RUCO As Filed	TEP Revised	TEP Difference	Explanation of TEP Revisions
Income Tax Expense	(16,130,352)	(5,695,687)	15,747,439	(19,049,439)	(2,919,086)	Reflects conformity changes and includes offsetting jurisdictional allocation impact of ($855K)
Transmission Expense Adjustment	95,464,952	95,464,952	95,464,952	93,719,409	(1,745,544)	Decrease in transmission expense reflects the impact of a usage reduction related to one of the Company's largest customers.
D&O Insurance	-	(25,000)	(25,153)	(21,105)	(21,105)	Accepted 50/50 sharing as proposed by RUCO and Staff.
Lobbying, Employee Recognition, Spot Award, Wellness - New	-	-	(548,924)	-	-	
Severance Pay	-	-	(329,665)	(329,665)	(329,665)	Removed severance pay as proposed by RUCO.
SGS Legal Expenses Lessor Dispute	-	(1,340,000)	-	-	-	
Total Adjustments to Operating Expense	24,441,665	8,854,929	(22,305)	10,845,501	(13,596,164)	
Total Net Adjustments	(219,890,083)	(204,303,347)	(194,590,791)	(221,072,365)	(1,182,282)	
Adjusted Operating Income	$98,381,058	$113,967,794	$123,680,350	$97,198,776	($1,182,282)	
Operating Income Deficiency	$67,517,257	$30,450,561	$10,717,810	$62,025,451	($5,491,806)	
Gross Revenue Conversion Factor	1.6223	1.6223	1.6223	1.6223	1.6223	
Increase in Gross Revenue Requirement	$109,534,118	$49,400,339	$17,387,642	$100,624,690	($8,909,428)	

Exhibit DJL – R – 2

TUCSON ELECTRIC POWER

COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT

TEST YEAR ENDED JUNE 30, 2015

ACC JURISDICTION

	TEP As Filed	RUCO As Filed	RUCO As Corrected	Difference	Explanations of RUCO As Corrected
Original Cost Rate Base - Unadjusted	$2,108,583,243	$2,108,583,243	$2,108,583,243	-	
Rate Base Adjustments					
Jurisdictional Allocation		(138,422,327)	(138,422,327)	-	
SGS CHF	(41,966,722)	(41,966,722)	(41,966,722)	-	
Fortis Merger Rate Base Adjustment	(522,398)	(522,398)	(522,398)	-	
Asset Retirement Obligation	-	-	-	-	
Post Test Year Plant	51,782,029	-	-	-	
Post Test Year Plant - Renewables	20,794,266	-	-	-	
Delayed Unitization	13,237,543	13,237,543	13,237,543	-	
Accumulated Deferred Investment Tax Credit (ITC)	30,341,626	30,341,626	30,341,626	-	
Accumulated Deferred Income Taxes	(58,308,686)	(58,308,686)	(53,547,344)	4,761,342	RUCO's adjustments to Rate Base did not include corresponding adjustments to ADIT. Company adjusted ADIT to reflect rate case adjustments as proposed by RUCO.
San Juan Unit 2	-	(0)	(0)	-	
Sundt Coal Handling facilities	(19,120)	(19,120)	(19,120)	-	
SGS Unit 1 Lease Equity (related to 14.1% acquisition in 2006)	6,855,471	6,855,471	6,855,471	-	
Sundt & San Juan M&S	1,225,594	1,225,594	1,225,594	-	

TUCSON ELECTRIC POWER

COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT

TEST YEAR ENDED JUNE 30, 2015

ACC JURISDICTION

	TEP As Filed	RUCO As Filed	RUCO As Corrected	Difference	Explanations of RUCO As Corrected
Head Quarters		(55,043,003)	(55,043,000)	3	
Working Capital	(27,325,154)	(25,313,900)	(27,351,091)	(2,037,191)	RUCO adjusted Company's Cash Working Capital worksheet to reflect RUCO"s adjustments using ACC jurisdictional values. However, the Company's Cash Working Capital worksheet uses pre-ACC jurisdictional values, then adjusts for the ACC jurisdictional ratio by the Revenue Requirements Model. Company corrected RUCO's Cash Working Capital worksheet to reflect pre-ACC jurisdictional values.
Total Adjustments	(3,905,553)	(267,935,924)	(265,211,769)	2,724,155	
Pro Forma OCRB	2,104,677,690	1,840,647,319	1,843,371,474	2,724,155	
Proposed Rate of Return	7.34%	6.76%	6.76%		
Required Operating Income OCRB	$154,416,180	$124,427,759	$124,611,912	184,153	
Fair Value Increment of Rate Base	$808,601,055	$741,672,017	$738,947,714	(2,724,303)	
Fair Value Rate Base (FVRB)	$2,913,278,745	$2,582,319,188	$2,582,319,188	-	
Proposed FVROR	5.69%	5.20%	5.21%		
Required Operating Income on FVRB	165,898,315	134,398,160	134,546,280	148,120	
Implied ROR on Fair Value Increment of Rate Base	1.42%	1.34%	1.34%		

TUCSON ELECTRIC POWER

COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT

TEST YEAR ENDED JUNE 30, 2015

ACC JURISDICTION

	TEP As Filed	RUCO As Filed	RUCO As Corrected	Difference	Explanations of RUCO As Corrected
Original Operating Income - Unadjusted	$318,271,141	$318,271,141	$318,271,141		
Operating Income Adjustments					
Operating Revenue Adjustments					
Lost Fixed Cost Revenue	(10,719,946)	(10,719,946)	(10,719,946)	-	
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)	(3,956,411)	(3,956,411)	-	
Base Cost of Fuel & Purchased Power	(17,815,595)	(17,815,595)	(17,815,595)	-	
Miscellaneous Service Revenue	284,370	284,370	284,370	-	
TEP Headquarters - Retail Space	250,000	250,000	-	(250,000)	RUCO removed the entire value of the building including the value of the retail space. Since the retail space is no longer in rate base, Company eliminated the rent credit to avoid RUCO's double counting.
Total Adjustments to Operating Revenues	(195,448,418)	(194,613,096)	(194,863,096)	(250,000)	
Operating Expense Adjustments					

TUCSON ELECTRIC POWER

COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT

TEST YEAR ENDED JUNE 30, 2015

ACC JURISDICTION

	TEP As Filed	RUCO As Filed	RUCO As Corrected	Difference	Explanations of RUCO As Corrected
REST and DSM	(19,891,996)	(19,891,996)	(19,891,996)	-	
Non-Retail & Non Recurring Revenue	(1,696,421)	(1,696,421)	(1,696,421)	-	
Springerville Units 3 & 4	(84,382,546)	(84,382,546)	(84,382,546.45)	-	
Sales of SO2 Allowances	47	47	47	-	
Sales for Resale	(162,821,057)	(162,821,057)	(162,821,057)	-	
Power Supply Management	(278,075)	(278,075)	(278,075)	-	
Base Cost of Fuel & Purchased Power	226,811,827	226,811,827	226,811,827	-	
Gila River O&M	6,130,964	6,130,964	6,130,964	-	
Springerville Unit 1	(11,558,130)	(11,558,130)	(11,558,130)	-	
Overhaul & Outage Normalization	5,176,492	(870,213)	4,419,896	5,290,109	The correction has two parts. The first is to correct for RUCO's math error. RUCO's adjustment was intended to levelize expenses to $8,177,594. However, RUCO levelized expense to $9,165 ,217. The second adjustment is to correct the frequency percent. RUCO's intention was to use a levelized frequency percentage over 11 years, however, their formula was averaging over 17 years.
Payroll Expense	2,264,794	2,264,794	2,264,794	-	
Payroll Tax Expense	151,051	151,051	151,051	-	
Pension & Benefits	2,004,436	1,056,440	1,576,055	519,615	RUCO did not include additional benefits included in revised pro forma adjustment. Company corrected for revised pro forma.
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

	TEP As Filed	RUCO As Filed	RUCO As Corrected	Difference	Explanations of RUCO As Corrected
Short-Term Incentive Compensation	702,960	(2,964,033)	(2,964,033)	-	
Rate Case Expense	107,834	27,834	40,708	12,874	RUCO did not use the ACC jurisdictional adjusted values in the adjustment. Company corrected RUCO's adjustment.
Injuries and Damages	1,419	1,419	1,419	-	
Membership Dues	(212,696)	(416,963)	(406,087)	10,876	RUCO applied the same ACC jurisdictional ratio to all EEI adjustments. The ACC jurisdictional ratio varied on some EEI charges.
Bad Debt Expense	(149,199)	(149,199)	(149,199)	-	
San Juan Unit 2 Direct Operating Cost	(3,921,687)	(3,921,687)	(3,921,687)	-	
Long Term Incentive Compensation	880,967	(639,979)	(431,510)	208,469	RUCO removed LTI based on company's revised/corrected pro forma. Since the correction was not included in the model, RUCO should have used the originally filed pro forma adjustment to remove LTI. Also, RUCO applied payroll tax at a rate of 7.65%. The payroll tax rate on LTI should be 1.45%.
Depr. & Amort. Expense	9,253,715	(9,202,556)	(5,499,223)	3,703,333	RUCO removed 12 months of depreciation expense for both post test year and post test year renewables. By doing so RUCO doubled the expense related to non revewable to post year year.
Sundt & San Juan M&S	408,531	408,531	408,531	-	
Property Tax Expense	3,119,696	2,554,799	2,554,799	-	
Asset Retirement Obligation	(393,590)	(393,590)	(393,590)	-	
SGS Common Facilities Lease	(1,195,980)	(1,195,980)	(1,195,980)	-	
San Juan Unit 1 SCNR O&M	955,223	955,223	955,223	-	
Fortis Merger Operating Income Adjustment	(31,176,174)	(31,176,174)	(31,176,174)	-	

TUCSON ELECTRIC POWER

COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT

TEST YEAR ENDED JUNE 30, 2015

ACC JURISDICTION

	TEP As Filed	RUCO As Filed	RUCO As Corrected	Difference	Explanations of RUCO As Corrected
TEP Headquarters	-	(942,257)	2,948,646	3,890,903	RUCO removed deprecation expense related to new building. Treated HQ building as owned by UNS and calculated rent at "the going market rate." Company correction included the removal of HQ building from rate base and allow $5.3M of annual rent expense.
Credit Card Processing Fees	3,475,500	-	-	-	
Income Tax Expense	(16,130,352)	15,747,439	12,579,068	(3,168,371)	Reflects impact of corrected pro forma postions including a jurisdictional allocation change of $8,577,635.
Transmission Expense Adjustment	95,464,952	95,464,952	95,464,952	-	
Jurisdictional Allocation	-	(19,532,187)	(19,532,187)	-	
D&O Insurance	-	(25,153)	(21,105)	4,048	RUCO did not use the ACC jurisdictional adjusted value in the adjustment. Company corrected RUCO's adjustment.
Lobbying, Employee Recognition, Spot Award, Wellness - New	-	(548,924)	(521,442)	27,482	RUCO did not use the ACC jurisdictional adjusted value for wellness expenses in the adjustment. Company corrected RUCO's adjustment.
Severance Pay - New		(329,665)	(238,519)	91,146	RUCO incorrectly included portion of severance pay that was capitalized in the amount disallowed (O&M = $217K, Capitalized=$112, Sum $329).
Total Adjustments to Operating Expense	24,441,665	(22,305)	10,568,179	10,590,484	
Total Net Adjustments	(219,890,083)	(194,590,791)	(205,431,275)	(10,840,484)	
Adjusted Operating Income	$98,381,058	$123,680,350	$112,839,866	($10,840,484)	
Operating Income Deficiency	$67,517,257	$10,717,810	$21,706,414	$10,988,604	
Gross Revenue Conversion Factor	1.6223	1.6223	1.6223	1.6223	
Increase in Gross Revenue Requirement	$109,534,118	$17,387,642	$35,214,596	$17,826,954	

TUCSON ELECTRIC POWER

COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT

TEST YEAR ENDED JUNE 30, 2015

ACC JURISDICTION

	TEP	RUCO	RUCO		
	As Filed	As Filed	As Corrected	Difference	Explanations of RUCO As Corrected

Exhibit DJL – R – 3

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
EXHIBIT 3

	TEP As Filed	ACC As Filed	ACC As Corrected	ACC Difference	Explanations of ACC As Corrected
Original Cost Rate Base - Unadjusted	$2,108,583,243	$2,108,583,243	$2,108,583,243	$0	
Rate Base Adjustments					
Jurisdictional Allocation (Demand and Energy)	-	-	-	-	
SGS CHF	(41,966,722)	(41,966,722)	(41,966,722)	-	
Fortis Merger Rate Base Adjustment	(522,398)	(522,398)	(522,398)	-	
Asset Retirement Obligation	-	-	-	-	
Post Test Year Plant	51,782,029	37,124,629	37,124,629	-	
Post Test Year Plant - Renewables	20,794,266	4,872,919	4,872,919	-	
Delayed Unitization	13,237,543	13,237,543	13,237,543	-	
Accumulated Deferred Investment Tax Credit (ITC)	30,341,626	30,341,626	30,341,626	-	
Accumulated Deferred Income Taxes	(58,308,686)	(58,303,521)	(53,004,227)	5,299,294	Staff's adjustments to rate base did not include corresponding adjustments to ADIT. Company adjusted ADIT to reflect rate case adjustments as proposed by Staff.
ADIT - Extension of Bonus Depreciation	-	(12,814,172)	(12,814,172)	-	
San Juan Unit 2	-	-	-	-	
Sundt Coal Handling facilities	(19,120)	880	880	-	
SGS Unit 1 Lease Equity (related to 14.1% acquisition in 2006)	6,855,471	6,855,471	6,855,471	-	
Sundt & San Juan M&S	1,225,594	1,225,594	1,225,594	-	
Head Quarters	-	-	-	-	
Working Capital	(27,325,154)	(19,387,724)	(19,122,961)	264,763	Staff adjusted Company's Cash Working Capital worksheet to reflect Staff's adjustments using ACC jurisdictional values. However, the Company's Cash Working Capital worksheet uses pre-ACC jurisdictional values, then adjusts for the ACC jurisdictional ratio via the Revenue Requirements Model. Company corrected Staff's Cash Working Capital worksheet to reflect pre-ACC jurisdictional values.
Accumulated Depreciation adj and LTI	-	9,020,000	-	(9,020,000)	The average remaining life as used in the Company's depreciation study is self correcting. Thus, no adjustment is necessary. Reducing the reserve balance overstates the asset value on which the Company is earning a return.
Total Adjustments	(3,905,553)	(30,315,876)	(33,771,819)	(3,455,943)	

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
EXHIBIT 3

	TEP As Filed	ACC As Filed	ACC As Corrected	ACC Difference	Explanations of ACC As Corrected
Pro Forma OCRB	2,104,677,690	2,078,267,367	2,074,811,424	5,564,057	
Proposed Rate of Return	7.34%	6.68%	6.68%		
Required Operating Income OCRB	154,416,180	138,763,150	$138,532,390	(230,760)	
Fair Value Increment of Rate Base	808,601,055	808,600,679	$803,994,234	(4,606,445)	
Fair Value Rate Base (FVRB)	2,913,278,745	2,886,869,000	$2,878,806,457	(8,062,543)	
Proposed FVROR	5.69%	5.00%	5.00%		
Required Operating Income on FVRB	165,898,315	144,418,355	$144,155,350	(263,005)	
Implied ROR on Fair Value Increment of Rate Base	1.42%	0.70%	0.70%		
Original Operating Income - Unadjusted	318,271,141	318,271,141	$318,271,141	$0	
Operating Income Adjustments					
Operating Revenue Adjustments					
Lost Fixed Cost Revenue	(10,719,946)	(10,719,946)	(10,719,946)	-	
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)	-	
Base Cost of Fuel & Purchased Power	(17,815,595)	(17,815,595)	(17,815,595)	-	
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)	(195,448,418)	(195,448,418)	-	
Operating Expense Adjustments					
Jurisdictional Allocation (Demand and Energy)	-	-	-	-	
REST and DSM	(19,891,996)	(19,891,996)	(19,891,996)	-	

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
EXHIBIT 3

	TEP As Filed	ACC As Filed	ACC As Corrected	ACC Difference	Explanations of ACC As Corrected
Non-Retail & Non Recurring Revenue	(1,696,421)	(1,696,421)	(1,696,421)	-	
Springerville Units 3 & 4	(84,382,546)	(84,382,546)	(84,382,546)	-	
Sales of SO2 Allowances	47	47	47	-	
Sales for Resale	(162,821,057)	(162,821,057)	(162,821,057)	-	
Power Supply Management	(278,075)	(278,075)	(278,075)	-	
Base Cost of Fuel & Purchased Power	226,811,827	226,811,827	226,811,827	-	
Gila River O&M	6,130,964	6,130,964	6,130,964	-	
Springerville Unit 1	(11,558,130)	(11,558,130)	(11,558,130)	-	
SGS Unit 1 Non Fuel O&M (50.5% Share)	-	-	-	-	
Overhaul & Outage Normalization	5,176,492	1,043,941	1,043,941	-	
Payroll Expense	2,264,794	1,121,186	1,121,186	-	
Payroll Tax Expense	151,051	76,051	76,051	-	
Pension & Benefits	2,004,436	2,050,431	1,576,433	(473,998)	The test year had $564,903 reflected in FERC 926 and $564,904 in FERC 426. The Company's pro forma moved the amounts reflected in FERC 426 (below the line) to FERC 926. Staff intended to remove 100% of SERP, but inadvertently only removed the amount reflected in FERC 426. Staff adjustment includes the revised pension and benefit amount as identified by the Company ($2,529,050)
Post-Retirement Benefits	1,339,160	1,339,160	1,339,160	-	
Short-Term Incentive Compensation	702,960	(2,803,734)	(2,803,734)	-	
Rate Case Expense	107,834	(36,208)	(36,208)	-	
Injuries and Damages	1,419	1,419	1,419	-	
Membership Dues	(212,696)	(212,696)	(212,696)	-	
Bad Debt Expense	(149,199)	(149,199)	(149,199)	-	
San Juan Unit 2 Direct Operating Cost	(3,921,687)	(3,921,687)	(3,921,687)	-	
Long Term Incentive Compensation	880,967	-	-	-	
Depr. & Amort. Expense	9,253,715	(1,665,318)	(1,588,163)	77,155	Staff assumes a 1 to 1 relationship on ACC jurisdictional ratios for post test year plant accumulated depreciation and depr. expense. ACC jurisdictional ratios are different.
Post Test Year Plant	-	-	-	-	
Sundt & San Juan M&S	408,531	408,531	408,531	-	
Property Tax Expense	3,119,696	2,694,696	2,694,696	-	
Asset Retirement Obligation	(393,590)	(393,590)	(393,590)	-	
SGS Common Facilities Lease	(1,195,980)	(1,195,980)	(1,195,980)	-	

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
EXHIBIT 3

	TEP As Filed	ACC As Filed	ACC As Corrected	ACC Difference	Explanations of ACC As Corrected
San Juan Unit 1 SCNR O&M	955,223	955,223	955,223	-	
Fortis Merger Operating Income Adjustment	(31,176,174)	(31,176,174)	(31,176,174)	-	
Lime Expense	-	-	-	-	
Credit Card Processing Fees	3,475,500	-	-	-	
Income Tax Expense	(16,130,352)	(5,695,687)	(5,591,094)	104,594	Impact of Company corrections to Staff adjustments.
Transmission Expense Adjustment	95,464,952	95,464,952	95,464,952	-	
D&O Insurance	-	(25,000)	(21,105)	3,895	Staff did not use the pre-ACC jurisdictional ratio amount to adjust for the elimination of 50% of D&O insurance. Company corrected staff's adjustment by eliminating 50% of ACC jurisdictional D&O insurance amount.
Lobbying, Employee Recognition, Spot Award, Wellness - New	-	-	-	-	
Severance Pay	-	-	-	-	
SGS Legal Expenses Lessor Dispute	-	(1,340,000)	(1,124,730)	215,270	Staff's adjustment is a total Company position. The $215,270 is to reflect the portion not allocable to all jurisdictions.
Total Adjustments to Operating Expense	24,441,665	8,854,929	8,781,845	(73,084)	
Total Net Adjustments	(219,890,083)	(204,303,347)	(204,230,263)	73,084	
Adjusted Operating Income	$98,381,058	$113,967,794	$114,040,878	$73,084	
Operating Income Deficiency	$67,517,257	$30,450,561	$30,114,472	($336,089)	
Gross Revenue Conversion Factor	1.6223	1.6223	1.6223	1.6223	
Increase in Gross Revenue Requirement	$109,534,118	$49,400,339	$48,855,097	($545,242)	

Exhibit DJL – R – 4

RUCO 11.02

Post Test Year Plant – Has the Company utilized the half-year convention when calculating accumulated depreciation on Post Test Year Plant?

RESPONSE:

The accumulated depreciation reflects a full year depreciation expense on the post-test year adjustment.

RESPONDENT:

Bernadette Porter

WITNESS:

Dallas Dukes

Exhibit DJL – R – 5

TUCSON ELECTRIC COMPANY
POST TEST YEAR
TEST YEAR ENDING JUNE 30, 2015

FERC	Project	Project Name	In Service Dates (A)	Post Test Year (B)	Total Depreciation (C)	ACC Juris. Ratio (D)	ACC Post Test Year Amount ('E)	ACC Depreciation (F)	NBV (G)
Projects Unitized									
	General								
303	D141OSP	Oracle Services Procurement	MAY-16	380,252	380,252	92.03%	349,945	349,945	-
303	D141AFR	2014 Acct Financial Reporting	MAY-16	2,365,016	450,479	92.03%	2,176,525	414,576	1,761,949
	Generation								
312	D14AD79	Selective Non-Catalytic Reduc	APR-16	9,774,013	257,057	89.78%	8,775,108	230,785	8,544,323
312	D13SK02	SGS U2 Mercury	MAY-16	1,075,679	21,729	89.78%	965,745	19,508	946,237
312	D13SE01	SGS U1 Mercury	MAR-16	498,459	8,673	89.78%	447,517	7,787	439,730
315	D02AB96	Irv #3 Step Transformer Replmt	JUN-16	1,660,946	204,462	89.78%	1,491,197	183,566	1,307,631
315	D08AB07	Sundt U3 MCC Replacement	JUN-16	258,865	31,938	89.78%	232,409	28,674	203,735
	Distribution								
362	D11DD93	NE T2A Swtchgr Replc	JAN-16	131,864	2,374	100.00%	131,864	2,374	129,491
		Sub-Total Projects Unitized		16,145,094	1,356,963		14,570,310	1,237,216	13,333,095
Projects Pending									
	Generation								
311	D13AC90	Sundt Cooling Tower Blowdown	DEC-16	158,920	16,758	89.78%	142,679	15,045	127,633
312	D12AC77	Sundt Condensate tank Piping	DEC-16	277,508	28,930	89.78%	249,147	25,974	223,173
312	D05AD32	San Juan Various Enviro Projs	DEC-16	220,886	7,786	89.78%	198,311	6,990	191,321
	Distribution								
362	D14NM15	Volt-Var Pilot Ph1 & 2	DEC-16	553,547	9,964	100.00%	553,547	9,964	543,583
362	D09EO02	Wilmot T2 Replacement	DEC-16	130,583	2,350	100.00%	130,583	2,350	128,232
367	D13LE28	RV- Tangerine West 3rd Fdr Tie	DEC-16	112,774	2,413	100.00%	112,774	2,413	110,360
		Sub-Total Projects Pending		1,454,218	68,202		1,387,041	62,737	1,324,303
		Grand Total		17,599,312	1,425,166		15,957,351	1,299,953	14,657,398
	Renewables								
344	D14PD43	Brt Buildout Plan Ft Huachuca Phase II	Aug-16	8,200,000	210,330	89.78%	7,361,960	188,834	7,173,126
344	NA	TEP Community Solar-Pima Cnty	SEP-16	10,000,000	256,500	89.78%	8,978,000	230,286	8,747,714
				18,200,000	466,830		16,339,960	419,120	15,920,840
			Grand Total	34,345,093.85	1,823,793.26		32,297,311.01	1,719,072.81	30,578,238.20

Exhibit DJL – R – 6

STAFF'S RESPONSE TO TUCSON ELECTRIC POWER COMPANY'S SECOND SET OF DATA REQUESTS TO ARIZONA CORPORATION COMMISSION UTILITIES DIVISION STAFF
DOCKET NO. E-01933A-15-0322
JUNE 24, 2016

Data Requests Regarding Direct Testimony of ACC Staff Witness Donna Mullinax

TEP 2.1: Regarding Ms. Mullinax's recommendation to limit Post Test Year Plant to plant that was in service by December 31, 2015. (Mullinax Direct at pages 8-9):

A. Does Staff agree that no ACC rule limits Post Test Year Plant to plant that was in service six months after the end of the test year. If not, please explain why not.

RESPONSE: **Staff agrees.**

RESPONDENT: Donna Mullinax

B. Does Staff agree that no written ACC policy limits Post Test Year Plant to plant that was in service six months after the end of the test year. If not, please explain why not.

RESPONSE: **Staff agrees.**

RESPONDENT: Donna Mullinax

C. Does Staff agree that in *EPCOR Water Arizona, Inc.*, Decision No. 75268 (Sep. 8, 2015), the Commission rejected RUCO's request to limit Post Test Year Plant to plant that was in service six months after then end of the test year. (See pages 16 to 17 of that Decision). If not, please explain why not.

RESPONSE: **Staff agrees that in the referenced *EPCOR Water Arizona, Inc.* case, Staff recommended the inclusion of Post Test Year plant additions that were completed by the end of the test year but were treated as CWIP, in addition to inclusion of projects that were still in CWIP but were completed by June 30, 2014 (Test Year - 12 months ended June 30, 2013). Staff stated that Commission rules contemplate the inclusion of Post Test Year plant in rate**

Rebuttal Testimony of

Michael E. Sheehan

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-1933A-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

REBUTTAL TESTIMONY OF

MICHAEL E. SHEEHAN

ON BEHALF OF

OF TUCSON ELECTRIC POWER COMPANY

JULY 25, 2016

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V. Useful Life Justification for San Juan Unit 1. 10

VI. Useful Life Recommendations for TEP's Local Area Natural Gas Resources. 166

VII. San Juan Generating Station Retrofit versus Retirement Analysis. 188

Exhibits

Exhibit MES-R-1: Jurisdictional Allocation Demand Factor

Exhibit MES-R-2: Gila River Unit 3 Avoided PPFAC Cost Estimate

Exhibit MES-R-3: Resource Planning Timeline

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Michael E. Sheehan. My business address is 88 East Broadway Blvd., Tucson, Arizona 85701.

Q. Did you file Direct Testimony in this proceeding?

A. Yes.

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. My Rebuttal Testimony is filed on behalf of Tucson Electric Power Company ("TEP" or the "Company").

Q. Which Commission Staff and/or Intervenor Testimony do you address in your Rebuttal Testimony?

A. My Rebuttal Testimony addresses the testimony filed on behalf of the Commission Staff ("Staff"), Arizonans for Electric Choice and Competition ("AECC") and the Residential Utility Consumers Office ("RUCO") in the following subject areas:

- Update on TEP's Base Cost Fuel and Purchase Power
  - Staff Witness Michael J. McGarry, Sr.
- The Long-Term Value of Springerville Unit 1
  - Staff Witnesses Michael J. McGarry, Sr. and Donna H. Mullinax
- Revised Jurisdictional Allocation Proforma
  - RUCO Witness Frank W. Radigan
  - AECC Witness Kevin C. Higgins
- Useful Life Justification for San Juan Generation Station
  - RUCO Witness Frank W. Radigan

- Sierra Club Witness Patrick W. Luckow
- Useful Life Recommendations for TEP's Local Area Gas Generation Fleet
  - Staff Witness Roxie McCullar
- San Juan Retrofit versus Retirement Analysis
  - Sierra Club Witness Patrick W. Luckow

II. TEP's REVISED BASE COST OF FUEL AND PURCHASE POWER.

Q. Does the Company have an updated estimate on the average cost of fuel and purchase power for the timeframe that the proposed TEP rates are likely to go into effect?

A. Yes. As part of this rebuttal, TEP's Resource Planning group updated its long term production cost model AuroraXMP.[1] AuroraXMP is currently used for determining the forward projection for TEP's cost of fuel and purchase power. Based on the forecast of forward natural gas and wholesale power prices as of June 2016 prepared by the energy consulting firm Wood MacKenzie,[2] TEP now forecasts the average base rate of fuel and purchase power to be approximately 3.2559¢/kWh as compared to 3.3692¢ in the November 5, 2015 Application. The cost estimate in Table 1 below is based on a forecast of PPFAC eligible costs from January 1, 2017 through December 31, 2017.

[1] AuroraXMP, Power Generation Forecasting Software by EPIS, http://epis.com/.
[2] Wood MacKenzie, North America Gas Markets Short-Term Outlook (June 2016).

Table 1 – Revised 2017 Base Cost of Fuel and Purchase Power

	January 2017 - December 2017
Base Cost of Fuel and Purchase Power ($000)	$281,730
TEP Electric Retail Sales, GWh	8,653
Average Annual Cost, ¢/kWh	3.2559

Forward Market Prices	January 2017 - December 2017
Palo Verde (7x24) Market, $/MWh	$35.65
Permian Natural Gas, $/mmBtu	$ 3.58

Q. Did the Company make any PPFAC proforma adjustments to the base cost of fuel estimate?

A. Yes. In order to capture the PPFAC rate impacts from the curtailment of TEP's largest customer, the Company reduced its retail load forecast for 2017 based on this customer's actual production curtailment from 80 MW to 65 MW. As a result of this reduction in mining demand, the Company's revised 2017 retail forecast decreased approximately 327 GWh or 3.7% in total retail sales from the prior forecast of 8,980 GWh to 8,653 GWh.

Q. Does the base cost of fuel and purchase power estimate still assume recovery of the non-fuel related costs associated with the 50.5% co-ownership share of Springerville Generating Station ("SGS") Unit 1?

A. No. As described by Company witness Kentton C. Grant in his Rebuttal Testimony in response to concerns raised by Staff Witnesses Michael J. McGarry, Sr.[3] and Donna H. Mullinax,[4] as well as AECC witness Kevin C. Higgins,[5] the Company is now proposing

[3] Direct Revenue Testimony of Michael J. McGarry, Sr, page 12, lines 7 - 22 and page 13, lines 1 - 14.
[4] Direct Testimony of Donna H. Mullinax, page 36, lines 10 - 22.
[5] Direct Revenue Testimony of Kevin C. Higgins, page 14, lines 4 - 7.

to recover the $16.2 million of O&M, property taxes and fuel handling costs through non-fuel base rates. As a result of this change, the revised 2017 average base cost of fuel and purchase power shown in Table 1 above excludes all non-fuel related costs associated with the 50.5% co-ownership share of SGS Unit 1.

Q. Did the Company make any other proforma adjustments to the base cost of fuel estimate?

A. Yes. Consistent with the Company's initial rate filing, the estimate in Table 1 above includes a proforma adjustment that credits the margins associated with a firm wholesale sale agreement between TEP and Shell Energy North America[6] ("Shell Energy").[7] This proforma adjustment reflects the forecasted wholesale sale margins from this contract for 2017[8] and reduces the 2017 base cost of fuel and purchase power by approximately $2.8 million. Although this is a long-term wholesale contract, TEP is proposing this adjustment since less than one year will be remaining on the contract when new retail rates are proposed to be implemented.

III. TEP's COST RECOVERY JUSTIFICATION ON THE 50.5% CO-OWNERSHIP SHARE OF SGS UNIT 1.

Q. Has the Company prepared any economic analysis in support of its decision to acquire the 50.5% co-ownership share of SGS Unit 1?

A. Yes. As described by Company witness Kentton C. Grant in his Rebuttal Testimony in response to concerns raised by Staff Witness Donna H. Mullinax,[9] as well as AECC

[6] Direct Revenue Testimony of Kevin C. Higgins, page 34, lines 18 - 21 and page 35, lines 1 - 2.
[7] On December 12, 2014, the Company entered into a day-ahead index call option with Shell Energy North America. The term of this wholesale call option expires December 31, 2017.
[8] Wholesale sale margins equal revenues less the allocated cost of fuel and purchase power to serve this contract.
[9] Direct Testimony of Donna H. Mullinax, page 37, lines 4 - 10.

witness Kevin C. Higgins,[10] a thorough economic analysis was been prepared. In September 2015, the Company hired PACE Global[11] to conduct a long-term assessment of TEP's generation portfolio to evaluate whether the acquisition of the remaining 50.5% of the co-ownership share of SGS Unit 1 would be in the best interest of TEP's retail customers.[12]

Q. Can you provide an overview of the study conducted by PACE Global?

A. Yes. PACE Global conducted a comprehensive risk-based analysis that evaluated seven different resource expansion plans. Three of the expansion plans assumed that the 50.5% co-ownership share of Springerville Unit 1 was acquired in 2017 and remained in the TEP generation portfolio under varying service lives assumptions that reflected possible retirement dates of 2025, 2030 and 2045. The other three expansion plans assumed that Springerville Unit 1 was retired by 2020 and the capacity was replaced with a mix of natural gas and renewable resources. The natural gas resource alternatives consisted of existing merchant combined cycle plants ("NGCC"), new build NGCCs and new combustion turbines, while the renewable resources consisted of solar and wind projects sited within Arizona or New Mexico. Finally, the last expansion plan reflects the generation portfolio assumptions from the 2014 Integrated Resource Plan ("IRP") and serves as a comparison against all of the expansion plans within the PACE Global study.

Q. What customer objectives or metrics did PACE Global utilize in its analysis?

A. PACE Global focused its analysis on three key objectives: least cost, rate stability, and

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[10] Direct Revenue Testimony of Kevin C. Higgins, page 14, lines 8 - 16.

[11] Pace Global, A Siemens Business, is a leading provider of strategic energy consulting services. Pace Global has provided consulting services to support the execution of business strategies, complex energy transactions, asset development, and operations focusing on select markets in the Americas. More information can be found at http://www.paceglobal.com/.

[12] The assessment assumes the acquisition of the non-owned capacity of SGS1 (195 MW) and operating the entire plant for longer periods of time than the defined alternatives, which retire 100% of the unit in 2020. Per the terms of the Settlement Agreement between Alterna Springerville LLC and LDVF1 TEP LLC, TEP assumes the cost of the non-owned portion of Springerville Unit 1 at $436/kW.

environmental compliance. PACE Global designed the portfolio analysis to evaluate the objectives based on the metrics referenced in Table 2 below:

Table 2 – PACE Global's Rate Payer Objectives and Metrics

Objective	Metric
Minimize Total Portfolio Cost	Net present value of the total revenue requirements of both fuel and non-fuel related costs ("NPVRR")
Manage Risks for Ratepayers and Achieve Stable Long-Term Power Costs	95th percentile of NPVRR
Achieve Environmental Compliance for CO_2 Emissions under the Clean Power Plan (CPP)	CO_2 emissions or emission rate credits from affected TEP-owned resources in comparison to CPP goals for Arizona

Q. Can you summarize some of the key conclusions from the PACE Global analysis and why the acquisition of the 50.5% co-ownership share of SGS Unit 1 is in the best interest of TEP's retail customers?

A. Yes. Below are some of the key conclusions from PACE Global's analysis regarding the acquisition of the 50.5% co-ownership share of SGS Unit 1. First, expansion plans that acquired the 50.5% co-ownership share of SGS Unit 1 reflected net present value revenue requirement outcomes that were lower by $326 million to $385 million relative to the expansion plans that retire SGS Unit 1 and replace the capacity with a combination of natural gas and renewable resources. Second, the option to preserve Springerville's coal capacity in the near-term and replace TEP's higher cost coal generation resources (e.g.,

San Juan) with a mix of natural gas and renewable resources in the longer term has value to TEP's rate payers. In terms of value, portfolios that retain SGS Unit 1 capacity longer perform better over the near term than those that retire it early and replace it with more natural gas capacity. Third, generation portfolios that retain the 50.5% co-ownership share of SGS Unit 1 maintained higher rate stability for TEP's retail customers due to reduced exposure to natural gas commodity risk and reduced commitments to other large capital investments in the near term. Finally, the acquisition of the 50.5% co-ownership share of SGS Unit 1 still allows TEP to meet compliance under the Final Rule of EPA's Clean Power Plan ("CPP").[13]

Q. What impact would the acquisition have on the Company's long-term resource diversification strategy?

A. As shown in TEP's 2016 Preliminary IRP, the Company will have the option to divest all of its San Juan coal fired generation over the next several years. Additionally, the Company's will have the option to cease its participation in all of its jointly-owned coal units by 2031.[14] Consequently, TEP will still be able to substantially reduce its reliance on coal-fired resources even with the acquisition of the co-owner share of SGS Unit 1.

Q. How do SGS Units 1 and 2 compare to the other coal-fired resources owned by TEP?

A. The Springerville Generating Station is significantly more valuable for a number of reasons. First, SGS Units 1 and 2 are the Company's newest coal units,[15] they have rail

[13] On August 3, 2015 the Environmental Protection Agency ("EPA") issued its Final Rule - Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; 40 CFR Part 60. http://www.gpo.gov/fdsys/pkg/FR-2015-10-23/pdf/2015-22842.pdf

[14] TEP's 2016 Preliminary IRP shows TEP's viable exit date options for the San Juan Generation Station, Navajo Generating Station and the Four Corners Power Plant, page 12.

[15] The Springerville Generating Station is comprised of four units. Unit 1 went into service in 1985 and Unit 2 went into service in 1990 and is owned by TEP. Unit 3 went into service in 2006 and is owned by Tri-State Generation and Transmission. Unit 4 went into service in 2009 and is owned by the Salt River Project.

access to competitive coal supplies and the day to day operations of the facilities are managed by the Company's highly trained personnel.[16] Second, not only are SGS Units 1 and 2 TEP's lowest cost coal-fired resources on a dollar per kilowatt hour basis, but they are the Company's most reliable coal-fired resources.[17] Third, the Springerville Generating Station is located in a strategic spot on TEP's transmission system and supports a significant portion of the Company's ancillary service requirements. Finally, the Company believes that the continued operation of SGS provides TEP with a low cost, low risk coal resource that enables the Company to maintain a reasonable level of fuel diversification within its generation portfolio.[18]

IV. JURISDICTIONAL ALLOCATION DEMAND FACTOR.

Q. Is the Company now proposing to update its jurisdictional demand allocation calculation due to some of the concerns raised by RUCO[19] and AECC[20]?

A. Yes. The Company is now proposing pro forma adjustments that include a new long-term wholesale contract that was entered into with Navopache Electric Cooperative ("NEC") in September 2015, and reflect the recent curtailment of operations by TEP's largest retail mining customer. Consistent with the Company's initial rate filing, TEP has also excluded from the jurisdictional demand allocation two expiring long-term wholesale contracts with Salt River Project ("SRP") and Shell Energy.

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[16] TEP currently employs over 440 employees at SGS and is the largest employer in Springerville, Arizona.
[17] In comparison to TEP's other coal-fired facilities, Springerville Units 1 & 2 have achieved the highest Equivalent Availability Factor in TEP's coal fleet based on the five year period from 2011 to 2015.
[18] TEP's 2016 Preliminary IRP shows the Company's energy portfolio in 2032 is comprised of 30% coal, 34% natural gas, 30% renewables and 6% purchase power. The retirement of SGS Units 1 and 2 would result in a disproportionate amount of energy sourced from natural gas, page 14.
[19] Direct Revenue Testimony of Frank W. Radigan, page 15, line 16 through page 17, line 2.
[20] Direct Revenue Testimony of Kevin C. Higgins, page 34, line 6 through page 36, line 10.

Q. Can you explain why the Company is proposing to exclude the SRP and Shell Energy contracts from this calculation?

A. TEP proposes to exclude the SRP contract because it expired on May 31, 2016. In addition, TEP proposes to exclude the Shell Energy contract because it will only be in effect for one year after rates are set in this rate case proceeding.

Q. Why does the Company feel that it is reasonable to exclude the Shell Energy Contract from the jurisdictional demand allocation in this rate case?

A. The exclusion of the Shell Energy contract from the jurisdictional demand allocation is reasonable for a number of reasons. The Shell Energy contact was put in place after the Company acquired 412 MW of capacity with the purchase of Gila River Unit 3.[21] The Shell Energy contract was intended to serve as a bridge to the anticipated retirement date of San Juan Unit 2 (December 31, 2017), and was expected to provide at least some recovery of non-fuel Gila River costs during this period.[22] Further, all the non-fuel costs associated with TEP's share of Gila River Unit 3 have been borne by TEP's shareholders since the purchase was closed in December 2014. During this same period Gila River Unit 3 has provided significant costs savings for TEP's retail customers through reductions in the PPFAC.[23] Finally, TEP is proposing to credit all of the wholesale revenues of approximately $8.4 million associated with the Shell Energy contract back to retail customers through the PPFAC during 2017. This adjustment is reflected in my updated cost of fuel and purchase power calculation shown above. In my view, this approach to the jurisdictional demand calculation provides for a more equitable allocation of the revenue requirements between the retail and the wholesale jurisdictions over the term that new retail rates will be in effect.

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[21] Direct Revenue Testimony of Frank W. Radigan, page 15, line 20.

[22] This timing reflects the same duration as the Shell Energy contract.

[23] Based on TEP's actual dispatch of Gila River Unit 3 since its acquisition in December 2014, TEP retail customers have avoided approximately $25.4 million in fuel and purchase power costs. See **Exhibit MES-R-2** attached to my Rebuttal Testimony.

Q. What wholesale demand allocator does the Company now propose?

A. Based on the pro forma adjustments described above, the Company is proposing to increase the wholesale demand allocation factor from 4.34% to 6.00%. **Exhibit MES-R-2** attached to my Rebuttal Testimony shows how this demand allocation was derived.

V. USEFUL LIFE JUSTIFICATION FOR SAN JUAN UNIT 1.

Q. Did any witnesses disagree with the Company's recommendation to use a remaining useful life of 2027 for San Juan Unit 1?

A. Yes. RUCO witness Frank W. Radigan recommends leaving the assumed San Juan Unit 1 retirement date at the previously established date of 2036.[24] In contrast, Sierra Club witness Patrick W. Luckow recommends an accelerated retirement date of 2022.[25]

Q. What is the basis for Mr. Radigan's recommendation?

A. Mr. Radigan states that there is insufficient evidence to support reducing the service life of San Juan Unit 1. Further, he argues that there is a case to be made that with the retirements of San Juan Units 2 and 3, the coal supply available for San Juan Units 1 and 4 could extend the life of the units beyond the Company's proposed retirement date of 2027.

Q. Do you agree with Mr. Radigan's position?

A. No. To say there is insufficient evidence to support a service life reduction is not in line with the reality facing many coal-fired generating plants today.[26] Historically, even older coal-fired generation resources maintained a competitive cost advantage over other

[24] Direct Revenue Testimony of Frank W. Radigan, page 18, line 10 - 11.
[25] Direct Testimony of Patrick W. Luckow, page 6, lines 2 - 7.
[26] As shown in the Company's 2016 IRP, TEP is on track to reduce 20% of its coal capacity by 2018.

generation resources due to the availability of low cost coal and less stringent environmental regulation. Today, higher environmental compliance costs, more stringent mining regulations, less favorable mine economics and increased plant maintenance costs and cheap natural gas have eliminated these cost advantages for a number of older coal-fired facilities throughout the country. In today's environment, for utilities like TEP with generation portfolios that have a disproportionate share of coal-fired generation, it is not unreasonable to expect strategically accelerated retirements for the "highest cost" coal-fired resources.[27]

Q. Is there other evidence in the public record that suggests that the economics of San Juan post 2022 are in question?

A. Yes. As part of the New Mexico Public Regulation Commission's ("NMPRC") Supplemental Stipulation for Public Service of New Mexico's ("PNM") request in its 2013 Certificate of Public Convenience and Necessity proceeding there were a number of questions related to the long-term economics of San Juan post 2022.[28] As a result of this uncertainty, the NMPRC ordered PNM to meet certain requirements related to its decisions on San Juan post 2022.

> After July 1, 2018, but no later than December 31, 2018, PNM shall make a filing with the Commission, and serve all parties to this case, to determine the extent to which SJGS should continue serving PNM's retail customers' needs after June 30, 2022. The filing shall be made before PNM has made a binding commitment to a post-2022 coal supply agreement, but after PNM has received firm pricing and other terms for the supply of coal at SJGS, unless PNM proposes not to pursue a coal

[27] "TEP is committed to follow through on its long-term portfolio diversification strategy to take advantage of other near-term opportunities to reduce its coal exposure at its higher cost TEP coal facilities." TEP's 2016 Preliminary IRP, page 12.

[28] Supplemental Stipulation filed on August 13, 2015. NMPRC Case No. 13-00390-UT.

supply post-2022. Under the assumption that SJGS does not continue to operate past 2022, PNM will issue an RFP as soon as practicable after the filing of the 2017 IRP that will request proposals for resources identified in the IRP as the most cost effective portfolio.

Q. You mentioned that unfavorable coal mine economics have eliminated cost advantages for a number of coal-fired facilities throughout the country. Can you explain?

A. Yes. As current long-term coal supply agreements expire, it is important to understand how the mine economics change going forward. If a mine operator must invest significant amounts of capital into development work in order to perform on a future coal supply agreement, the mine operator will require a long-term commitment from the plant owner in order to recover that investment. If the mine operator cannot obtain a long-term commitment, the miner would need to attempt to recover its investment over a shorter period, likely resulting in coal pricing that is not competitive relative to today's projected long-term natural gas prices.

Q. How do the mine economics play into San Juan's outlook on its coal supply going forward beyond June 2022?

A. To understand the mine economics at San Juan, it is important to consider the original San Juan Coal Company ("SJCC") mining plan that was developed in conjunction with the long-term coal supply agreement ("CSA") that was executed in 1980. Under that agreement SJCC was obligated to supply coal to all four units at San Juan through December 31, 2017. In addition, the San Juan Project Participant Agreement ("SJPPA") had a term through June 30, 2022. Based on those original agreements, it was expected that by the end of December 2017, the plant participants would need to determine if the mining operation would only continue through June 2022 or for some longer period of

time. Based on recent mining plan cost studies, mining plans that discontinued operations at the end of June 2022 would enable the plant participants to avoid significant investments at the mine prior to the June 2022 plant retirement. In the case where the plant participants wanted to extend the life of the mine beyond June 2022, the mine plan cost studies indicate that significant investments in mine development work would need to start as early as 2019 in order to avoid supply disruptions post June 2022.

Q. Mr. Radigan assumes that the early retirement of San Juan Units 2 and 3 at the end of 2017 could make coal available to extend the service life of San Juan Unit 1 beyond 2027. Is that a viable scenario?

A. No. As I explained above, the issue of determining the plant service life for San Juan Unit 1 is related to mine economics beyond June 2022. While the early retirements of San Juan Units 2 and 3 do provide some additional flexibility to extend the life of the mine, it was this flexibility that enabled the participants to negotiate a cost-effective coal supply extension ("Westmoreland CSA") with Westmoreland Coal Company ("Westmoreland") through June 2022.

Q. Can you explain how the early retirement of San Juan Units 2 and 3 enabled the participants to negotiate a cost-effective coal supply extension through June 2022?

A. Yes. It was not until the San Juan participants committed to retire Units 2 and 3 by the end of 2017 that the feasibility of obtaining a reasonably priced coal supply agreement through June 2022 became a viable option. This reduced demand for coal and the "harvest-mode" contract structure enabled Westmoreland to offer competitively priced coal for the next seven years while providing all the plant participants a commercially viable option to exit the San Juan project in June 2022.

Q. Given that all the San Juan Project Agreements, along with the Westmoreland CSA, have a term that expires on June 30, 2022, does the Company plan to continue to stay in the project post June 2022?

A. While the Company has not committed to exit the San Juan project at the end of June 2022, based on what we know today, the likelihood that TEP remains in the project beyond June 2022 is not high. It is anticipated that significant amounts of capital will need to be invested in development work by the mine operator as early as 2019 in order for the San Juan Generating Station to have adequate coal supplies under a two unit configuration post June 2022. Over the next two years, the plant participants plan to negotiate terms for a new coal supply extension with Westmoreland for operations post June 2022. By the end of 2018, TEP will determine if it intends to exit the project by June 30, 2022[29] or renegotiate new agreements with the remaining participants to extend operations of both the plant and the mine.

Q Are there other factors that would likely cause San Juan Unit 1 to be retired before 2036?

A. Yes. In addition to the future coal supply price uncertainty, San Juan Units 1 and 2 are TEP's highest cost coal-fired generating facilities on a dollar per megawatt-hour basis. This high cost profile along with the uncertainty related to future coal pricing, environmental compliance risk and low cost natural gas makes San Juan Unit 1 the next coal unit to be targeted for retirement within the TEP generation portfolio.[30]

Q Given that it is not a high probability outcome that TEP continues to stay in San Juan Unit 1 post 2022, what is your rationale for the 2027 retirement date?

A. While continued operations of San Juan Unit 1 for TEP post 2022 are not a high

[29] TEP may consider options that include changes in plant ownership shares, unit shutdowns or sale of generation assets to third parties. TEP's 2016 Preliminary IRP, page 12.
[30] Ibid

probability outcome, there may be a viable scenario where TEP's participation in the San Juan project goes beyond June 2022. As I mentioned above, as the plant participants work with Westmoreland to develop a mine extension plan post June 2022, there may be a scenario where the mine can competitively operate under a one unit configuration for a short period of time. It is this scenario that TEP uses as the basis for the 2027 retirement date for San Juan Unit 1. As the Company makes plans to diversify away from coal, it is appropriate from a rate making standpoint to make adjustments to the plant service lives as the likelihood of these accelerated plant retirements become more certain.

Q Does the Company agree with Patrick W. Luckow's recommended retirement date of 2022?

A. No. Rather than request to change the service life of San Juan Unit 1 to June 2022, the Company is taking an incremental approach in this rate case to change the service life from 2036 to 2027. Until TEP makes its final decision in 2018 regarding San Juan, the Company feels the 2027 retirement date provides a balanced approach that limits the near-term rate impacts on customers. It is contemplated that in TEP's next rate case, the Company will have a definitive retirement date set on San Juan Unit 1 and will propose a plant depreciation strategy[31] that is in the best interest of TEP's current and future customers.

[31] Given that the outcome around San Juan Unit 1 could result in a full unit retirement, a short-term extension or a sale of TEP's ownership share to a third-party, in the Company's next rate case, TEP would propose a recovery strategy that would limit the rate impact on its customers.

VI. USEFUL LIFE RECOMMENDATIONS FOR TEP'S LOCAL AREA NATURAL GAS RESOURCES.

Q. Have any witnesses recommended using different service lives for some of the units in the Company's local area natural gas fleet.

A. Yes. Rather than using the Company's proposed ten year life extension recommendations, Staff witness Roxie McCullar is recommending using a final retirement year of 2032 for Sundt Steam Units 1 and 2; North Loop CT Units 1, 2, and 3; and Sundt CT Units 1 and 2.[32] Table 3 below provide an overview of these resources.

Table 3 – TEP's Local Area Natural Gas Units

Generating Units	Unit Capacity (MW)	Retirement Date in Current Depreciation Rates	Company Proposed Retirement Year	Staff's Proposed Retirement Year
H.W Sundt 1	80	2018	2028	2032
H.W Sundt 2	80	2020	2030	2032
H.W Sundt 3	105	2022	2032	2032
H.W Sundt CT 1	25	2017	2027	2032
H.W Sundt CT 2	25	2017	2027	2032
North Loop CT 1	24	2017	2027	2032
North Loop CT 2	24	2017	2027	2032
North Loop CT 3	24	2017	2027	2032

[32] Direct Revenue Testimony of Roxie McCullar, page 8, line 8.

Q. What is the basis for Staff's recommendation?

A. Staff witness Roxie McCullar's testimony indicates that the 2032 retirement date is based on data taken from an exhibit contained in TEP's 2016 Preliminary IRP.[33] These values were taken from a section of the report based on the Company's preliminary loads and resource assessment.

Q. Does this preliminary IRP assessment represent the Company's expectations regarding the useful life of its local generating units listed in Table 3 above?

A. No. The 2016 IRP is a preliminary report. The Company plans to file a final report in April 2017 based on full assessment of its resource portfolio. As part of this final report the Company is evaluating the long-term viability of TEP's local area natural gas fleet. Based on work completed to date,[34] the Company is projecting a need for quick-start, fast ramping natural gas peaking units between 2022 and 2025 for the purpose of managing the operational challenges related to the integration of higher levels of renewable resources.[35] The 2017 Final IRP report will reflect TEP's anticipated retirement dates for these local area natural gas resources.

Q. Does TEP still propose using its recommended service life extension of ten years?

A. Yes. While it is possible that some of these local area resources could potentially still be in service in 2032, given our future resource needs and our transition away from coal to more efficient natural gas resources and renewables, it is more likely that at least 50% of these older less efficient local area natural gas resources will be retired and replaced with newer technologies by 2025.

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[33] Table 5, Page 35 from TEP's 2016 Preliminary IRP Report.

[34] TEP is currently evaluating the possible retirement of some of its current local area resources with the replacement of new natural gas reciprocating engines ("RICE"). Information on RICE is presented on page 47 of the 2016 Preliminary IRP and an update on TEP's IRP plan was also presented at the 2016 IRP Workshop that was held at the Arizona Corporation Commission on June 18, 2016.

[35] https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf .

VII. SAN JUAN GENERATING STATION RETROFIT VERSUS RETIREMENT ANALYSIS.

Q. Did any witnesses raise any concerns regarding the Company's retrofit decisions on San Juan Unit 1?

A. Yes, Sierra Club Witness Patrick W. Luckow believes that TEP relied primarily on PNM's cost-benefit analysis rather than conduct its own detailed review in its retrofit decisions on San Juan Unit 1.[36]

Q. Is it true that the TEP relied on PNM's analysis related to the Company's retrofit decisions at San Juan?

A. No. The Company never relied on PNM's analysis related to the retrofit decisions on San Juan Unit 1. In fact, Mr. Luckow's testimony related to the PNM analysis has no relevance in this case, because the analysis he refers to is based on PNM's generation fleet and is completely unrelated to the resource decisions for TEP.

Q. Did the Company perform its own analysis related to the retrofit decisions on San Juan Unit 1?

A. Yes. Between July 2012 and the May of 2013, the Company analyzed in depth a series of options around the operations at the San Juan Generating Station ("SJGS"). These options included: 1.) the installation of selective catalytic reduction ("SCR") technology on all four SJGS units, 2.) the closure of all four units at SJGS by December 2017, or 3.) the retirement of two SJGS units and the installation of selective non-catalytic reduction ("SNCR") technology on the remaining two units.[37] Based on the Company's internal

[36] Direct Testimony of Patrick W. Luckow, page 15, lines 10 - 12.

[37] While the three scenarios described above describe the outcomes related to the entire station, TEP's internal analysis only considers the cost and benefits associated with its ownership share of Units 1 and 2.

analysis, it was determined that retiring Unit 2 and installing SNCR controls on Unit 1 ("SNCR Option") was $54 million to $63 million lower on a net-present-value basis versus a complete shutdown on both Units 1 & 2.

Q. In addition to being the least cost alternative at the time, what other factors went into the Company's position to proceed with the SNCR Option at SJGS?

A. The SNCR Option decision was made as part of TEP's overall portfolio strategy at the time. From a generation portfolio standpoint, a full shutdown of Units 1 and 2 at San Juan by 2017 was seen as a risky alternative given the uncertainty related to the potential early retirements at Four Corners Power Plant ("FCPP"), the Navajo Generating Station ("NGS"), and Unit 4 at the Sundt Generating Station as well as the potential loss of generation at the Springerville Generating Station ("SGS"). With approximately 950 MW of TEP's generation portfolio (43% of the Company's total resource capacity) at risk of near-term retirement, the Company made its decision in June 2013 to support the SNCR Option.[38]

Q. Does Mr. Luckow's suggestions that the Company should have re-evaluated its retrofit decisions on San Juan Unit 1 post 2013 have any merit?

A. No. Given the significant lead time necessary to engineer, procure equipment and construct the project, the company was required to commit to the retrofit decision on San Juan Unit 1 in October 2013. TEP's Engineering and Operating Committee vote in October 2013 to approve the SNCR Option contractually committed the Company to the retrofit project with spending on capital expenditures starting in late 2013. Any costs related to the SNCR Option in any subsequent resource planning decisions would have been considered a sunk cost.

[38] **Exhibit MES-R-3** attached to my Rebuttal Testimony summarizes this early retirement risk in further detail.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

Exhibit MES – R – 1

TUCSON ELECTRIC POWER COMPANY
ACC/FERC JURISDICTION - DEMAND ALLOCATION FACTOR

As Filed

DEMAND ALLOCATON - 2015

Line No.	Date	Retail System Peak	SRP	NTUA	TOUA	Shell	Trico	Sub-Total FERC	Removes SRP & Shell	Total	Line No.	
		(a)	(b)	(c)	(d)	('e)	(f)	(g)	(h)	(i)		
1	June, 2015	2,206	100	41	5	100	50	296	96	2,302	1	
2	July, 2015	2,066	100	48	5	100	50	303	103	2,169	2	
3	August, 2015	2,214	100	40	5	100	50	295	95	2,309	3	
4	September, 2015	1,995	100	35	5	100	50	290	90	2,085	4	
5	Total	8,481						1,185	385	8,866	5	
6	Average (Line 5/ 4)	**2,120.25**							**96.2**	**2,216.5**	6	
7	Demand Allocation Factor (Line 6 - (a)/(i) and (h)/(i)	95.66%							4.34%		7	**100.00%**

Revised

DEMAND ALLOCATON - 2017

Line No.	Date	Retail System Peak	NEC	NTUA	TOUA	Shell	Trico	Sub-Total FERC	Removes Shell	Total	Line No.
		(a)	(b)	(c)	(d)	('e)	(f)	(g)	(h)	(i)	
1	June, 2017	2,131	41	48	4	100	50	243	143	2,274	1
2	July, 2017	2,309	44	53	4	100	50	251	151	2,460	2
3	August, 2017	2,258	33	52	4	100	50	239	139	2,397	3
4	September, 2017	2,060	34	39	3	100	50	226	126	2,186	4
5	Total	8,758						959	559	9,317	5
6	Average (Line 5/ 4)	**2,189.57**							**139.7**	**2,329.3**	6
7	Demand Allocation Factor	94.00%							6.00%		7

Demand Report
AuroraXMP
2017 Base Cost of Fuel Nominal | 7/8/2016 8:06:31 AM

Loads & Resource Summary, MW	1/1/2017	2/1/2017	3/1/2017	4/1/2017	5/1/2017	6/1/2017	7/1/2017	8/1/2017	9/1/2017	10/1/2017	11/1/2017	12/1/2017
Retail Demand (Metered Load)	1,218.0	1,300.0	1,176.0	1,284.0	1,730.0	1,990.0	2,150.0	2,109.0	1,928.0	1,527.0	1,200.0	1,268.0
Total Firm Wholesale	214.4	203.8	179.4	159.7	146.7	142.8	150.6	139.2	126.4	156.6	180.9	211.2
Reserve Requirements	214.9	225.6	203.3	216.6	281.5	319.9	345.1	337.2	308.2	252.5	207.1	221.9
Total Forward Sales	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Retail, Firm & Reserves	1,747.2	1,829.4	1,658.7	1,760.3	2,258.2	2,552.7	2,745.6	2,685.4	2,462.6	2,036.1	1,688.1	1,801.1
Total Thermal Generation	2,557.5	2,557.5	2,557.5	2,557.5	2,557.5	2,557.5	2,557.5	2,557.5	2,557.5	2,557.5	2,557.5	4,199.0
Total Firm Purchases	83.6	83.6	83.6	83.6	83.6	83.6	83.6	83.6	83.6	83.6	83.6	167.3
Total Fuel & Purchase Power	2,641.1	2,641.1	2,641.1	2,641.1	2,641.1	2,641.1	2,641.1	2,641.1	2,641.1	2,641.1	2,641.1	4,366.3
City Gate Peak Retail Demand	1,288.6	1,368.7	1,240.8	1,362.9	1,852.9	2,131.3	2,309.5	2,257.9	2,059.6	1,619.6	1,269.0	1,347.3

Sales Demand, MW	1/1/2017	2/1/2017	3/1/2017	4/1/2017	5/1/2017	6/1/2017	7/1/2017	8/1/2017	9/1/2017	10/1/2017	11/1/2017	12/1/2017
Retail Demand	1,218.0	1,300.0	1,176.0	1,284.0	1,730.0	1,990.0	2,150.0	2,109.0	1,928.0	1,527.0	1,200.0	1,268.0
Firm Wholesale												
Salt River Project	-	-	-	-	-	-	-	-	-	-	-	-
Navajo Tribal Utility Authority	82.8	80.0	60.1	53.8	44.5	47.9	52.7	52.0	39.4	51.4	67.3	82.8
Navopache Electric Cooperative	78.0	69.9	67.0	53.2	49.2	41.3	44.1	33.3	33.9	52.8	61.1	75.7
TRICO	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Shell Option Sale												
Tohono O'odham Utility Authority	3.6	3.9	2.3	2.7	2.9	3.6	3.8	3.8	3.1	2.4	2.5	2.7
Total Firm Wholesale	214.4	203.8	179.4	159.7	146.7	142.8	150.6	139.2	126.4	156.6	180.9	211.2
Reserve Requirements	214.9	225.6	203.3	216.6	281.5	319.9	345.1	337.2	308.2	252.5	207.1	221.9
Total Forward Sales	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Retail, Firm & Reserves	1,647.2	1,729.4	1,558.7	1,660.3	2,158.2	2,452.7	2,645.6	2,585.4	2,362.6	1,936.1	1,588.1	1,701.1
Distribution Loss	5.79%	5.29%	5.51%	6.15%	7.11%	7.10%	7.42%	7.06%	6.83%	6.06%	5.75%	6.25%

Exhibit MES – R – 2

Exhibit MES-R-2

Gila River Unit 3 Avoided PPFAC Cost Estimate

Based on Actuals through June 2016, Forecast through December 2016

2015 TEP Gila River - Unit 3	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	2015
1 Total Gila River Generation for TEP, MWh	133.1	104.5	27.0	140.3	124.2	145.7	176.8	167.7	161.9	72.1	169.9	219.1	1,642.3
2 Palo Verde ICE, On-Peak , $/MWh (1)	$27.44	$25.30	$28.60	$26.64	$27.58	$37.30	$37.02	$37.64	$33.67	$28.77	$23.05	$21.42	$29.53
3 Palo Verde ICE, Off-Peak, $/MWh (1)	$23.78	$23.15	$26.43	$20.49	$25.17	$25.60	$27.64	$26.91	$24.68	$23.50	$20.29	$19.03	$23.89
4 Market Value of Replacement Energy	$3,494	$2,593	$755	$3,438	$3,330	$4,870	$5,930	$5,605	$4,927	$1,857	$3,715	$4,462	44,977.1
5 Less Gila River Fuel Expenses	-$4,032	-$2,089	-$972	-$3,021	-$3,204	-$3,961	-$4,804	-$4,722	-$4,164	-$1,888	-$2,620	-$3,551	(39,028.5)
6 Avoided Energy Costs (2)	-$538	$504	-$217	$417	$126	$909	$1,126	$882	$763	-$31	$1,095	$911	5,948.6
7 Avoided Capacity Savings (3)	$627	$627	$627	$627	$627	$627	$627	$627	$627	$627	$627	$627	7,524.0
8 Total Deferred Savings (Line 4 + 5 + 7)	$89	$1,131	$410	$1,044	$753	$1,536	$1,753	$1,509	$1,390	$596	$1,722	$1,538	13,472.6
Cumulative Deferred Savings	$89	$1,220	$1,630	$2,674	$3,427	$4,962	$6,716	$8,225	$9,616	$10,212	$11,934	$13,473	

Notes:

1 Reflects the price from the Intercontinental Exchange (ICE) weighted based on Gila River dispatch

2 Capacity Purchases are $1.52 per kW/month

2016 TEP Gila River - Unit 3	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	2015
1 Total Gila River Generation for TEP, MWh	217.4	149.7	117.8	184.5	132.7	118.1	101.8	101.1	86.8	73.2	69.3	63.2	1,415.7
2 Palo Verde ICE, On-Peak , $/MWh (1)	$21.46	$18.60	$17.21	$20.67	$21.02	$35.28	$28.32	$29.96	$25.86	$26.33	$25.89	$26.84	$24.79
3 Palo Verde ICE, Off-Peak, $/MWh (1)	$19.50	$18.37	$13.38	$15.19	$17.27	$31.86	$17.44	$19.18	$17.61	$21.59	$21.69	$21.81	$19.57
4 Market Value of Replacement Energy	$4,478	$2,771	$1,849	$3,407	$2,628	$4,069							19,202.1
5 Less Gila River Fuel Expenses	-$3,950	-$2,427	-$1,624	-$3,301	-$3,055	-$3,408							(17,764.4)
6 Avoided Energy Costs (2)	$528	$345	$225	$106	-$427	$662	$399	$319	$544	$390	$592	$687	4,368.3
7 Avoided Capacity Savings (3)	$627	$627	$627	$627	$627	$627	$627	$627	$627	$627	$627	$627	7,524.0
8 Total Deferred Savings (Line 4 + 5 + 7)	$1,155	$972	$852	$733	$200	$1,289	$1,026	$946	$1,171	$1,017	$1,219	$1,314	11,892.3
Cumulative Deferred Savings	$14,627	$15,599	$16,451	$17,184	$17,384	$18,672	$19,698	$20,644	$21,815	$22,832	$24,051	$25,365	

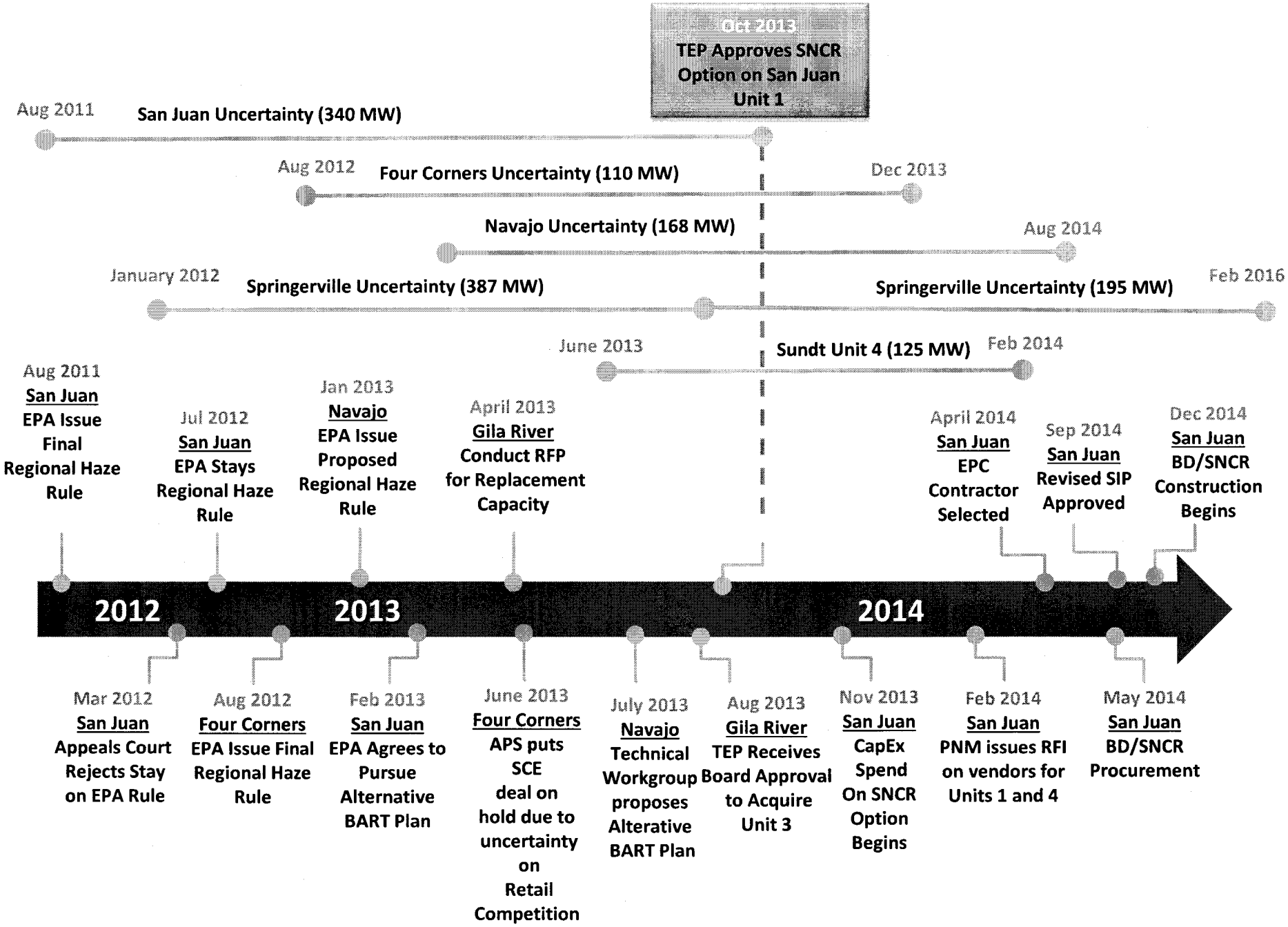
Notes:

1 Reflects the price from the Intercontinental Exchange (ICE) weighted based on Gila River dispatch

2 Capacity Purchases are $1.52 per kW/month

Exhibit MES – R – 3

Exhibit MES-R-3



Rebuttal Testimony of

Ramondo J. Robey

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-1933A-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

REBUTTAL TESTIMONY OF

RAMONDO J. ROBEY

ON BEHALF OF

OF TUCSON ELECTRIC POWER COMPANY

JULY 25, 2016

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Exhibits

Exhibit RJR-R-1: PPFAC Charts

Exhibit RJR-R-2: Hourly Prices

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Ramondo J. Robey and my business address is 88 East Broadway, Tucson, Arizona, 85701.

Q. Did you file Direct Testimony in this proceeding?

A. No.

Q. What is your position with Tucson Electric Power Company ("TEP" or the "Company")?

A. I am the Manager of Fuels Planning and Hedging.

Q. Please describe your education and experience.

A. I received a Bachelor of Arts degree in Philosophy from Northwestern University in 1993, a Master of Finance from the University of Arizona in 2002, and became a CFA Charterholder in 2005. I was hired by Tucson Electric Power Company ("TEP" or the "Company") in 2002. I worked in the Credit and Capital resources department as an Analyst for the Company until 2006, when I moved to Wholesale Marketing and Trading as Portfolio Manager. In that role, I was responsible for term-trading and hedging of natural gas and wholesale power. From 2010 through 2013, I served as Manager of Day-Ahead Trading and Hedging. In 2013, I moved into TEP's Fuels Department as Manager of Fuels and Hedging.

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. My Rebuttal Testimony is filed on behalf of TEP.

Q. Which Commission Staff or Intervenor Testimony do you address in your Rebuttal Testimony?

A. My Rebuttal Testimony addresses the testimony filed on behalf of the Commission Staff ("Staff"), and Arizonans for Electric Choice and Competition ("AECC") in the following subject areas:

- Company Proposed PPFAC Modifications
  - Staff Witnesses Michael J. McGarry, Sr.
- PPFAC Risk-Sharing Mechanisms
  - AECC Witness Kevin C. Higgins
- Margins from Long-Term Sales Contracts
  - AECC Witness Kevin C. Higgins

II. COMPANY PROPOSED PPFAC MODIFICATIONS.

Q. Has any witness raised concerns regarding the Company's proposed changes to the Purchase Power Fuel Adjustment Clause ("PPFAC")?

A. Yes. Staff witness Michael J. McGarry, Sr. did not support the Company's proposals to (i) use a percentage based PPFAC rate instead of the current kilowatt hour ("kWh") rate and (ii) use a 12 month historical rolling average PPFAC rate instead of the current annual PPFAC adjustment.[1]

Q. Does TEP concur with Staff's positions on these two issues?

A. In part. The Company is willing to withdraw its request for a percentage based PPFAC rate. However, due to significant benefits that I explain below, TEP still requests that the PPFAC rate be set based on a 12 month historical rolling average of actual costs.

[1] Direct Rate Design Testimony of Michael J. McGarry, Sr. (June 24, 2016), Executive Summary.

Q. Please explain the benefits of the Company's proposed use of the 12 month rolling average for the PPFAC rate.

A. There are two primary benefits. First, the use of the 12 month rolling average would improve the predictability of anticipated PPFAC charges by eliminating the Forward Component and True-Up Component used in the current PPFAC rate. Rather, the PPFAC rate would be based upon a monthly calculation of actual historical costs. The PPFAC rate would no longer be based on estimated future costs or the true-up of the difference between the estimate and actual results.

Second, the 12 month rolling average PPFAC rate would be limited in monthly movement by a monthly collar.[2] The current form of the PPFAC has, at times in the past, resulted in significant bill impacts upon the annual reset of the PPFAC rate. Under the Company's proposal, regardless of realized costs, the Total Average Rate (defined as the PPFAC Rate plus the Base Fuel Rate) would not change by more than 1% from month to month, thus limiting customer bill volatility to a pre-authorized amount. See Table 1 below.

Table 1 – Example of Monthly PPFAC Change

PPFAC Eligible Costs, ($000)	$281,486,500
Retail Sales, KWh	9,043,900
Total Average Rate, ¢/kWh	0.3112

Monthly Collar Limit, %	1%

Prior Month Rate, ¢/kWh	0.3052
Maximum Rate from Prior Month (+ 1%), ¢/kWh	0.3083
Minimum Rate from Prior Month (- 1%), ¢/kWh	0.3021

Applicable Total Average Rate, ¢/kWh	0.3083

[2] The PPFAC monthly collar limits the monthly PPFAC adjustment to + or – 1% per month.

Moreover, the calculation of historical costs would include adding the ending bank balance as of the last month into the calculation. For example, in Table 1, if the ending bank balance in December of 2015 were an over-collection of $10 million, then the amount of PPFAC eligible costs used to create the Calculated Total Average rate would reduce to $271,486,500.[3]

Q. Why is inclusion of the bank balance important?

A. Inclusion of the bank balance augments the PPFAC calculation by introducing a component that would allow the PPFAC balance to constantly move towards zero, regardless of over or under-collection. While 12 month rolling averages have been used for UNS Electric and UNS Gas fuel clauses for a number of years, not using the bank balance variable in those rate calculations has resulted in delays in crediting refunds to customers when the amounts have not met the thresholds prescribed in those companies' plans of administration.[4]

Q. Would moving to a 12 month rolling average smooth bill volatility for customers?

A. Yes. Please see **Exhibit RJR-R-1**. Historically, the process of using a lagged True-Up Component as well as a forecasted Forward Component has led to a single annual event serving as the change in PPFAC rate for customers. Table 2 below details the magnitude of the bill impacts which the single annual PPFAC adjustment has had on customers.

Table 2 – PPFAC Bill Impacts

Effective Date of New PPFAC Rate	Apr-12	Jul-13	May-14	Oct-14	Apr-15	May-16
PPFAC Rate ¢/kWh	0.0077	0.0014	0.001	0.005	0.0068	0.0015
Average Monthly Bill Impact (1)	$6.20	$1.12	$0.81	$4.03	$5.48	$1.21

(1) Based on Average Annual Usage of 806.25 kWh/Month

[3] [Actual PPFAC Eligible Costs – Over or (Under) Collection] = PPFAC Eligible Costs used to calculate Applicable Total Average Rate.

[4] Staff is recommending incorporating the bank balance in the current UNS Electric rate case. The Commission has approved a 12-month rolling average fuel rate for UNS Electric in its 2012 rate case, and for other utilities.

Exhibit RJR-R-1 details the effective PPFAC rate which would have resulted from both the use of a 12 month rolling average and incorporating the bank balance in the 12 month cost calculation.

Q. Would moving to a 12 month rolling average increase bill complexity for customers?

A. No. As noted above, both UNS Gas and UNS Electric utilize 12 month rolling averages. To my knowledge, there have been no customer complaints regarding bill complexity. By comparison, though the Company notifies customers of the annual PPFAC rate changes, we have received customer complaints regarding the magnitude of bill impacts resulting from such changes. In addition, the Commission moved the entire gas industry in Arizona, including Southwest Gas, to rolling average Purchased Gas Adjustors in the late 1990's.[5] At the conclusion of that process, the Commission noted, "To summarize Staff's findings, the PGA mechanism is performing as it was expected to and there does not appear to be any major problems with it. The mechanism allows the PGA rate to adjust over time to reflect the changes in the price of natural gas, while minimizing to the extent possible the sudden swings in the PGA rate applied to customers' monthly bills."[6] These are the same benefits, reflecting changes in price while preventing sudden swings, which moving to a 12 month rolling average PPFAC will provide.

Q. Would moving to a 12 month rolling average create challenges for Staff in reviewing the PPFAC rate?

A. No. Staff is experienced in the workings of the fuel recovery mechanisms of both UNS Gas and UNS Electric. Staff was supportive of changing the UNS Electric PPFAC from an annual reset model, similar to TEP's, to a 12 month rolling average. The improvement

[5] See Staff Report on Purchased Gas Adjustor Mechanisms, October 19, 1998 in Docket No. G-00000C-98-0568 and Decision Nos. 61225 (October 30, 1998) and 62994 (November 3, 2000) in that same docket.
[6] Decision No. 62994 (November 3, 2000) at page 1, Finding of Fact No. 5.

of adding the bank balance to the calculation of historical costs adds further surety that the bank balance will consistently move towards zero.

III. PPFAC RISK-SHARING MECHANISMS.

Q. Has any witness recommended that a risk-sharing mechanism be incorporated in the Company's PPFAC?

A. Yes. AECC Witness Kevin C. Higgins recommended a 70/30 risk-sharing mechanism in the PPFAC.[7]

Q. Do you agree with these recommendations?

A. No. Mr. Higgins' rationale for the sharing mechanism is unsubstantiated and the Company does not agree with these recommendations for the reasons below.

Q. Would operations and dispatch decisions be affected by a risk-sharing mechanism?

A. No. The Company manages operations and dispatch decisions based upon prudent utility practices and the lowest cost resources available. More specifically, in order to stress the Company's emphasis on reliable operations, the Company incorporates Equivalent Availability Factor ("EAF")[8] targets as a significant part of its yearly corporate goals.[9] The Company also practices prudent preventative maintenance on its operated units,[10] thereby increasing the availability of the generation resources when they are called upon. The Company's dispatch decisions are determined by system loads, generation available,

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[7] Direct Testimony of Kevin C. Higgins on behalf of Freeport Minerals Corporation and AECC – Revenue Requirement (June 3, 2016), page 6, lines 3-5.

[8] EAF is defined as the percentage of time in a given operating period in which a generating unit is available without any outage and equipment deratings.

[9] Each year, EAF is a component of the Company's Performance Enhancement Plan ("PEP") goals, which reward employees for performance above targeted goals. This plan is designed identically for executive and non-executive employees.

[10] See Direct Testimony of Company Witness Michael E. Sheehan, page 5.

regional prices, natural gas pipeline conditions, and expected volatility of hourly load. Mr. Higgins agrees that operations and dispatch decisions require a "sophisticated approach to managing utility owned resources,"[11] and provides no evidence that the Company is not, in fact, utilizing prudent utility practices in the way the Company currently manages the dispatch of its generation fleet.

Q. Historically, has the ACC and Staff been supportive of the Company's hedging practices?

A. Yes. As described in the direct testimony of Company witness Michael Sheehan, Staff only had one recommendation following the last PPFAC audit in relation to Company's hedging and procurement practices. Mr. Sheehan provides an overview on how the Company implemented Staff's recommended change referenced as Modification H-2.[12] Staff noted no problems in the Company's hedging practices in the last TEP rate case.

Q. How would the Company's hedging practices be affected by a sharing mechanism?

A. Employing a sharing mechanism would adjust the Company's intended use of its already accepted hedging program.[13] The Company utilizes hedges in the same accepted manner as other end-users, to offset future changes in the fair value of cash flows of an asset or liability. In the Company's case, its liability is the obligation to deliver reliable power to customers at a just and reasonable cost. The Company also employs hedges to manage price volatility in the power and natural gas markets. Incorporating a sharing mechanism alters the function of the Company's hedging practices and more closely aligns it with the definition of speculative trading. Speculative trading is defined as initiating a position with intention of profiting from a movement in the underlying price of the instrument or

[11] Direct Testimony of Kevin C. Higgins on behalf of Freeport Minerals Corporation and AECC – Revenue Requirement (June 3, 2016), page 40, lines 5-7.
[12] Direct Testimony of Michael Sheehan, Page 50, line 4.
[13] The Company's System Optimization and Hedging Policies are reviewed and approved by Staff. Any changes made to these policies are submitted to Staff as a standard course of business.

related commodity. Mr. Higgins' proposal of a sharing mechanism incentivizes the Company to view its hedging activities more in line with speculative trading activities, whereby the Company would stand to gain (or incur losses) from arbitrage. Ironically, the Company's risk policies expressly prohibit speculative trading as a noncore business activity. The Company's goal of providing customers with reliable, low-cost, and low volatility power supply already align with our customers' interests. Implementation of a payoff structure for the Company's hedging activity does not present a further benefit to customers and would, in fact, be counterproductive.

Q. Did the Company review other companies' PPFACs, specifically those which contained sharing mechanisms?

A. Yes, the Company did review the PPFACs of the companies noted in Mr. Higgins' testimony, in particular the plan of administration of Rocky Mountain Power ("RMP-W") because it contains a 70/30 sharing mechanism.[14] The RMP-W fuel clause in Wyoming is known as the Energy Cost Adjustment Mechanism ("ECAM"). Our review of the ECAM, as well as other sharing mechanisms, made clear that the sharing mechanism which Mr. Higgins is recommending is not about risk management or hedging. It also does not address prudency. Rather, the sharing mechanism proposed by Mr. Higgins addresses forecast accuracy. The actual costs incurred under the ECAM are compared to the Company's forecasted costs for the year. In the case where actual costs are lower than forecast, RMP-W is able to retain 30% of the variance to forecast, while customers receive 70%. In the case where actual costs are above the forecast, RMP-W is not allowed to recover 30% of the variance to forecast, while customers incur 70% of the variance. The allocation of 30% of costs, while symmetrical, is driven solely by the RMP-W's forecast variances. Based on my review of RWP-W's ECAM, I conclude that

[14] Direct testimony of Kevin C. Higgins on behalf of Freeport Minerals Corporation and AECC – Revenue Requirement (June 3, 2016), page 43, line 18.

the sharing mechanism is really only a test of the forecast itself, rather than a determination of the company's prudent behavior. Finally, Mr. Higgins asserts that there is an issue of properly motivating the Company in order for the Company to make prudent fuel related decisions. Following such an assumption, by requesting that the company in question then provide its own benchmarking forecast employs circular reasoning.

Q. Are there administrative concerns regarding a risk-sharing mechanism?

A. Yes, in the Final Evaluation Report of PacifiCorp's trial sharing program in Utah earlier this year,[15] the regulatory burden in managing the program is repeatedly referenced as a key issue. Also, in the states which Mr. Higgins mentioned (Oregon, Washington, Idaho, Montana, and Wyoming),[16] each of the plans of administrations for the states' utilities feature complex delineation between what is and what is not within the utilities' control. For those items deemed not to be in the utilities' control, for example retail load, there are balancing components created to make up for differences in actual retail load and the amount projected in the forecast. Also, there are allowances for renewable energy growth, hydroelectric generation volatility, and many components which do not exist within TEP's current PPFAC Plan of Administration. The addition of a sharing mechanism will entail more than an arbitrary selection of a sharing amount. Based on my review of these proposed sharing mechanisms, TEP's PPFAC Plan of Administration would need to be reevaluated as a whole to address a number of forecast modeling and regulatory rate complexities.

[15] Final Evaluation Report of PacifiCorp's EBA Program by The Division of Public Utilities Utah Department of Commerce dated May 20, 2016.

[16] Direct testimony of Kevin C. Higgins on behalf of Freeport Minerals Corporation and AECC – Revenue Requirement (June 3, 2016), page 43, line 18.

Q. What issues did Mr. Higgins show evidence for which support the recommendation of a 70/30 PPFAC risk-sharing mechanism?

A. None. Mr. Higgins did not identify any specific issues with the Company's PPFAC to justify moving to a 70/30 sharing mechanism. The Company's hedging policies were not found to be lacking nor imprudent, nor were any costs which were recovered through the PPFAC determined to be unreasonable. Mr. Higgins's recommendation for a 70/30 PPFAC sharing mechanism was solely based upon the assumption that the Company would behave differently if there were a sharing mechanism in place.

Q. Did Mr. Higgins acknowledge the increased risk inherent in forecasting volatile solar and wind generation when recommending a 70/30 risk-sharing mechanism?

A. No. Mr. Higgins' recommendation ignored the presence and growth of intermittent weather driven resources. His proposal to introduce a risk-sharing mechanism fails to address the difficulty in not only forecasting wind and solar generation, it also ignores the operational impacts caused by the presence of these resources. For example, when wind brakes must be applied in high winds, fast responding resources (typically natural gas units) must ramp to compensate for lost generation. When this occurs intra-day, natural gas must be procured at prices at a premium to day-ahead prices. Similar events occur when there is a loss of solar generation. During instances where solar and wind are over-generating versus forecast, conventional generation must be curtailed, with the most reactive units reducing output first. These units are typically natural gas fired units, leaving coal units' output unchanged. Such a generation configuration in a low natural gas price environment, meaning natural gas units may dispatch at a lower cost than coal units, is suboptimal and certainly not forecasted. The prior examples represent a small sample of the difficulties posed by wind and solar when comparing actual operations to forecast. Mr. Higgins makes no mention of these risks when advocating for a risk-sharing mechanism.

Q. What other issues influence the Company's responses regarding a risk-sharing mechanism?

A. The Company has addressed the issue of cost allocation throughout the current rate case. Decreasing the Company's ability to recover prudently incurred fuel costs does not demonstrate a reasonable approach to addressing the changing environment for regulated utilities. The changing environment is affected by increasing renewable penetration, fundamental shifts in hourly market prices due to renewables,[17] shifts in customer usage patterns, coal supplier bankruptcies, and increasing dependence upon natural gas which is subject to supply disruptions. The feasibility of any risk-sharing mechanism needs to take into account the large number of risks outside the Company's control which have a larger impact on the fundamental changes to forward fuel and wholesale power prices.

IV. MARGINS FROM LONG-TERM SALES CONTRACTS.

Q. Has any witness recommended that long-term wholesale contract margins be used to lower retail PPFAC pricing?

A. Yes. AECC Witness Kevin C. Higgins recommended that revenues from long-term wholesale contracts be credited against costs in the PPFAC, unless those contracts had non-fuel costs allocated to them in the Company's last rate case.[18]

Q. Do you agree with these recommendations?

A. No, the Company does not agree with this proposed treatment of long-term wholesale sales in between rate cases.

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[17] See **Exhibit RJR-R-2** which details the changing price environment in SP-15, which has high renewable penetration. Of note, is the now evident lack of historical on-peak shaping.

[18] Direct testimony of Kevin C. Higgins on behalf of Freeport Minerals Corporation and AECC – Revenue Requirement (June 3, 2016), page 6, lines 8-11.

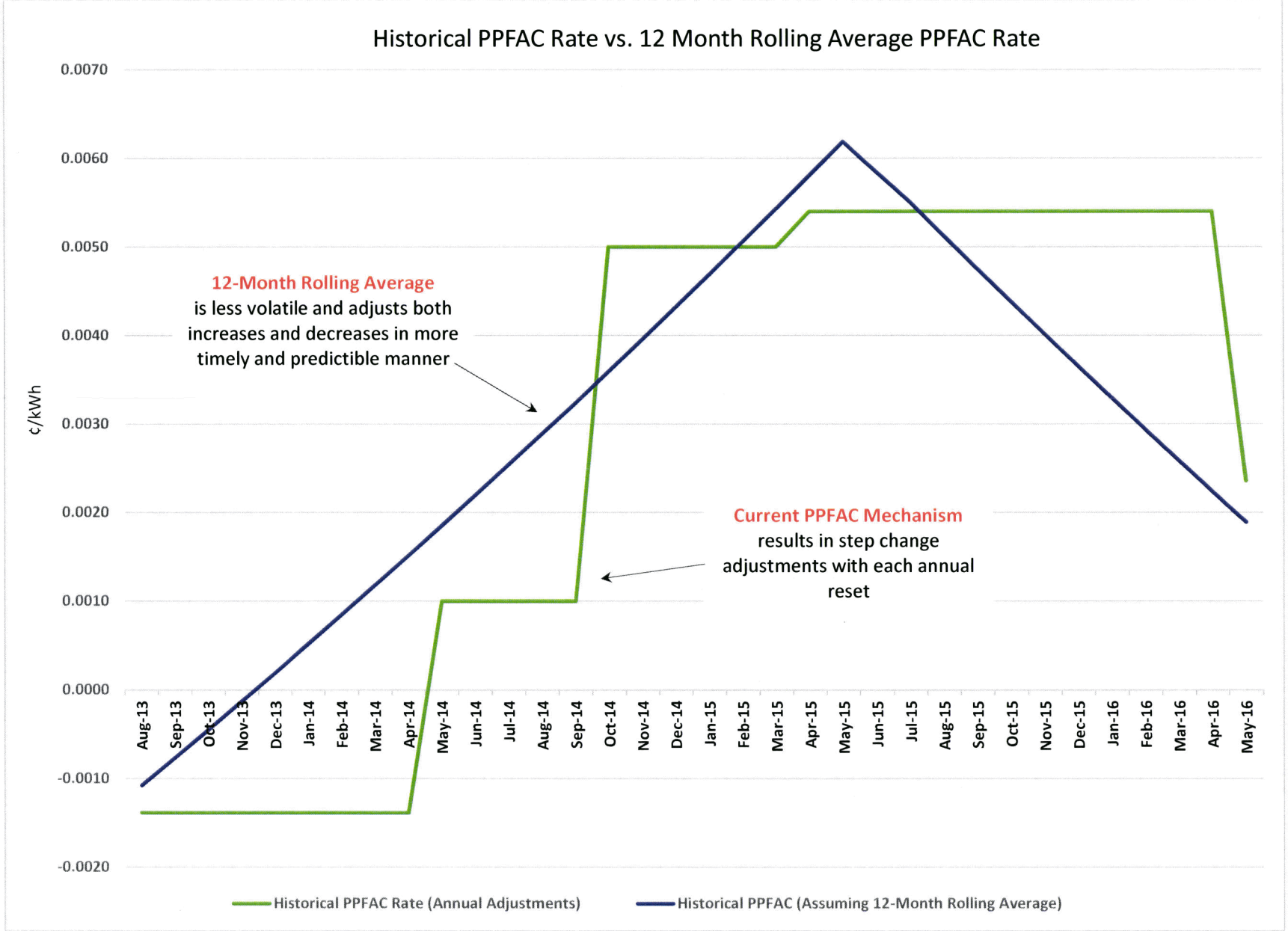
Q. Why are margins from long-term sales excluded from the PPFAC?

A. As discussed in the Rebuttal Testimony of TEP witnesses Michael Sheehan and Dallas Dukes, the Company allocates a percentage of non-fuel costs to long-term wholesale contracts in each rate case, thereby ensuring that retail customers pay only for the retail portion of total generation costs. By contrast, margins from short-term wholesale sales should be, and indeed are, credited back 100% to rate-payers through the PPFAC since they are used to optimize system operations and reduce net costs to retail customers over shorter periods of time.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

Exhibit RJR – R – 1


Historical PPFAC Rate vs. 12 Month Rolling Average PPFAC Rate
0.0070
0.0060
0.0050
0.0040
0.0030
0.0020
0.0010
0.0000
-0.0010
-0.0020
¢/kWh
12-Month Rolling Average
is less volatile and adjusts both increases and decreases in more timely and predictible manner
Current PPFAC Mechanism
results in step change adjustments with each annual reset
Aug-13
Sep-13
Oct-13
Nov-13
Dec-13
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
Jul-14
Aug-14
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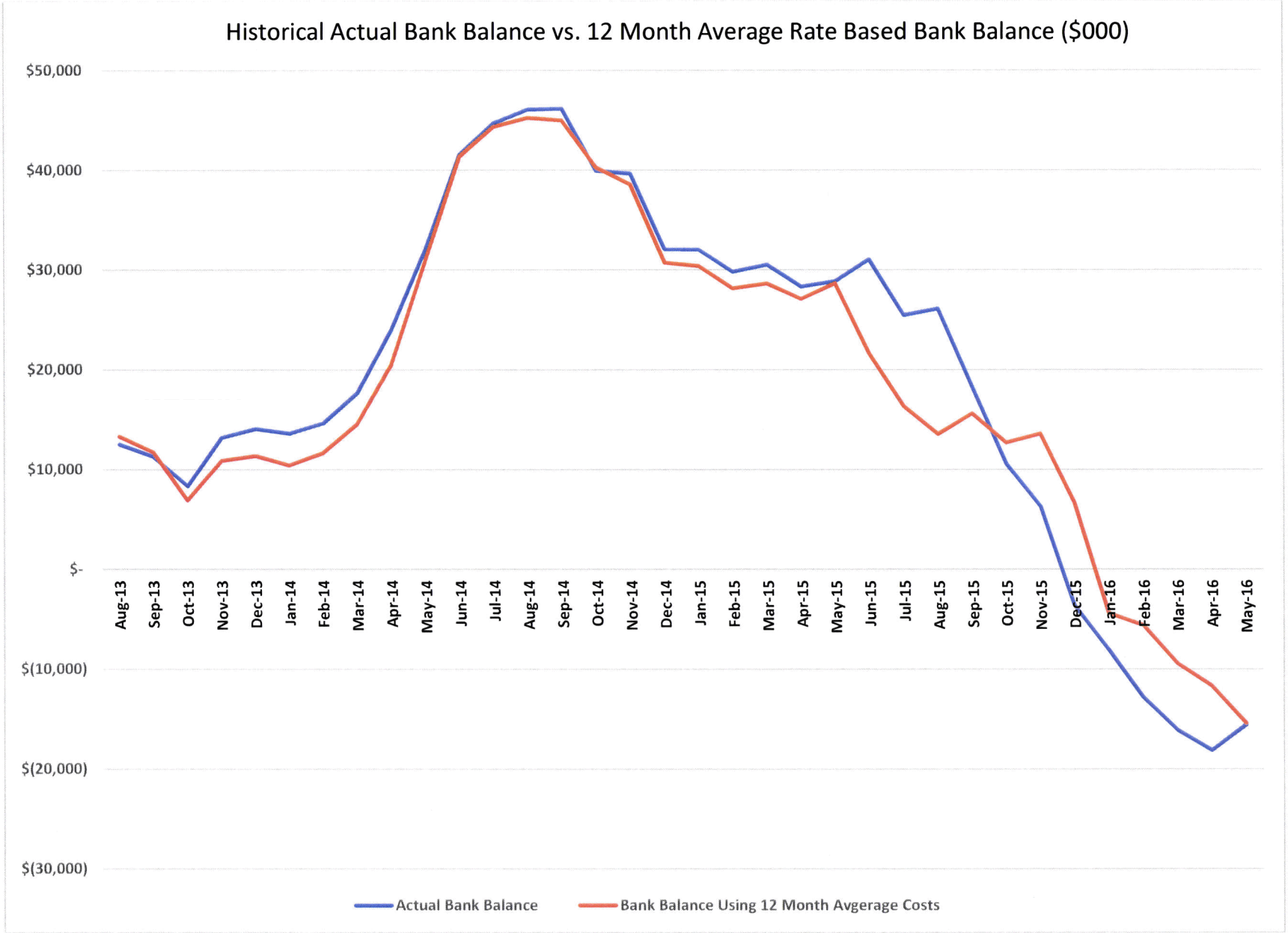
May-15
Jun-15
Jul-15
Aug-15
Sep-15
Oct-15
Nov-15
Dec-15
Jan-16
Feb-16
Mar-16
Apr-16
May-16
Historical PPFAC Rate (Annual Adjustments)
Historical PPFAC (Assuming 12-Month Rolling Average)


Historical Actual Bank Balance vs. 12 Month Average Rate Based Bank Balance ($000)
$50,000
$40,000
$30,000
$20,000
$10,000
$-
$(10,000)
$(20,000)
$(30,000)
Aug-13
Sep-13
Oct-13
Nov-13
Dec-13
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
Jul-14
Aug-14
Sep-14
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Jan-15
Feb-15
Mar-15
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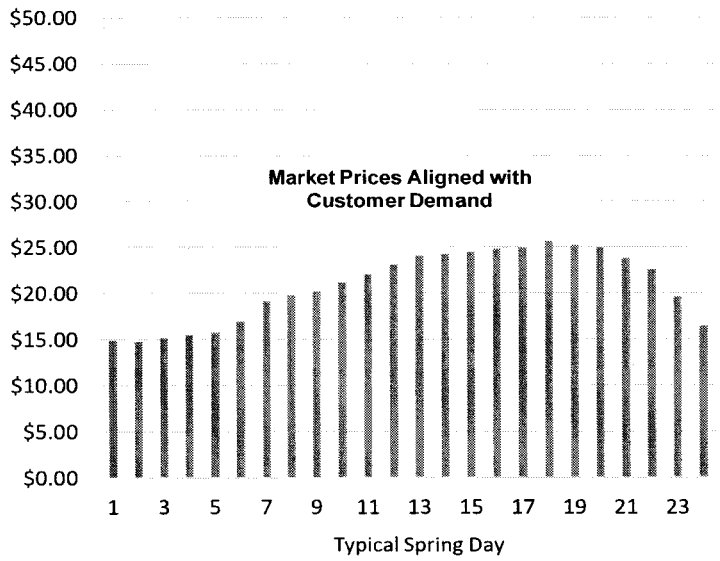
May-15
Jun-15
Jul-15
Aug-15
Sep-15
Oct-15
Nov-15
Dec-15
Jan-16
Feb-16
Mar-16
Apr-16
May-16
Actual Bank Balance
Bank Balance Using 12 Month Avgerage Costs

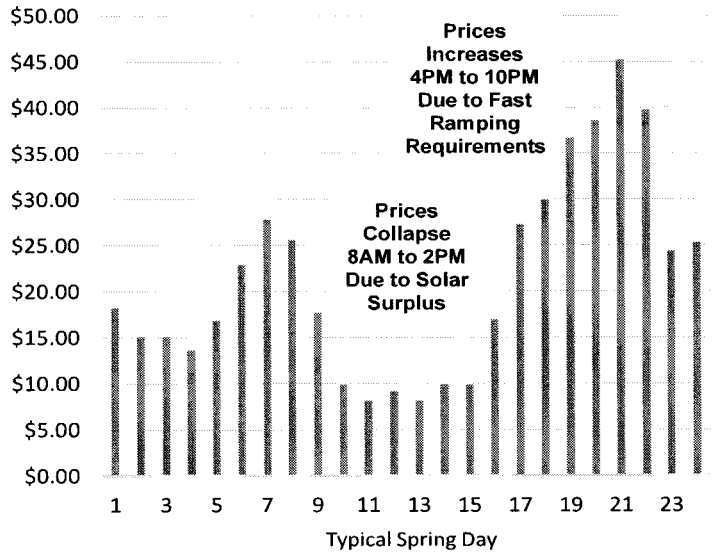
Exhibit RJR – R – 2

Solar Penetration Impacts on Hourly Wholesale Power Prices

Historical Hourly Price Curves ($/MWh)



CAISO Spring 2016 Price Curves ($/MWh)



Wholesale power prices are in process of undergoing a fundamental hourly price shift to accommodate the integration of solar resources

As Presented in TEP's Integrated Resource Planning workshop at the Arizona Corporation Commission, July 18, 2016 - DOCKET No. E-00000V-15-0094

Rebuttal Testimony of

Mark C. Mansfield

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

REBUTTAL TESTIMONY OF

MARK C. MANSFIELD

ON BEHALF OF

OF TUCSON ELECTRIC POWER COMPANY

JULY 25, 2016

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II. Balanced Draft. 2

III. Overhaul Averaging. 5

Exhibits

Exhibit MCM-R-1: Unit 1 Revised SIP Compliance Budget Approval

I. Introduction.

Q. Please state your name and business address.

A. My name is Mark C. Mansfield. My business address is 88 E Broadway, Tucson, Arizona 85702.

Q. By whom are you employed and what are your duties and responsibilities?

A. I am employed by Tucson Electric Power Company ("TEP" or the "Company") as Vice President Energy Resources.

Q. Please describe your background and work experience.

A. I have a Bachelor of Science degree in Mechanical Engineering from Brigham Young University, and a Master of Business Administration degree from the University of Utah. Before coming to TEP, I was employed in various capacities by PacifiCorp, an electric utility that serves parts of Utah, Wyoming, Idaho, Oregon, Washington and California. My primary focus during that tenure was in the operations and maintenance of large power plants. I served as an engineer and maintenance supervisor at the Carbon Plant; as Maintenance Superintendent at the Hunter Station; as Director of Technical Support for PacifiCorp's Generation Engineering Group in Salt Lake City, Utah; as the Plant Manager for the Naughton, Huntington, and Hunter Power Stations; and as Vice President of Thermal Operations, with responsibilities for PacifiCorp's coal-fired, gas-fueled, and geothermal generation assets and operations, including environmental and employee health and safety.

Q. What have been your responsibilities while employed by TEP?

A. Since joining the Company in June 2008, I have been responsible for the operations of the H. Wilson Sundt Generating Station and have overseen the Company's fleet of

combustion turbines, as well as the Company's interests in its power plants operated by other companies. In my current position, I am responsible for all the TEP generation assets.

Q. Did you file Direct Testimony in this proceeding?

A. No.

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. My Rebuttal Testimony is filed on behalf of TEP.

Q. Which Commission Staff or Intervenor Testimony do you address in your Rebuttal Testimony?

A. My Rebuttal Testimony addresses the testimony filed on behalf of Western Resource Advocates ("WRA") Steven S. Michel. I also address Staff witnesses Michael McGarry's proposed adjustment to the period for averaging overhaul expenses.

II. <u>Balanced Draft.</u>

Q. What issues does Mr. Michel raise in his direct testimony?

A. Mr. Michel asserts that the Balanced Draft ("BD") technology installed on San Juan Unit 1 is not a prudent and used and useful investment[1].

Q. What is the basis for WRA challenging the installation of BD?

A. WRA believes that the BD installation was not required to comply with any applicable ambient air quality requirements or other regulations.[2]

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[1] Direct Testimony of Steven S. Michel, page 3, lines 10-13.
[2] Direct Testimony of Steven S. Michel, page 3, lines 8-9.

Q. Can you provide an overview on the BD technology installed on San Juan Unit 1?

A. When fuel is combusted in a utility boiler, there is a large increase in gas volume. There are two types of furnaces used in the utility industry. The first type is called a positive pressure boiler. In this design the pressure inside the furnace is higher than atmospheric pressure. Because of this pressure difference if there are any leaks in the boiler casing or at any penetrations, flue gas and fly ash will escape to the outside atmosphere. The second type of boiler is called a balanced draft boiler. In a balanced draft design, the pressure inside the furnace is below atmospheric pressure. As a result if there are any cracks, holes or penetrations, outside air leaks into the boiler rather than flue gas or fly ash escaping.

Q. What are the advantages of a positive pressure boiler?

A. The only real advantage of a positive pressure boiler is that the induced draft fan can be sized smaller.

Q. What are the disadvantages of a positive pressure boiler?

A. The major disadvantage of a positive pressure boiler is that if there is any kind of opening or crack in the boiler casing, flue gas and fly ash escape to the atmosphere. A boiler like San Juan 1 will expand by one foot or more in length from cold to hot. Due to the high temperatures involved, metal must be used to seal the boiler. This sealing system is called the casing. Because of the thermal expansion the casing does crack resulting in leaks. Boilers also require soot blowers which must penetrate the casing. In a positive pressure boiler special seals must be used to contain the gas. These seals regularly fail due to the ash and temperatures to which they are exposed. For optimum operations, boiler heat transfer surfaces need to be visually inspected by operators. In this type boiler there are only a few viewing ports which use aspirated air to allow visual inspection.

Q. Are there other concerns with a positive pressure boiler?

A. The other concerns are employee health and safety, environmental protection and housekeeping. As the casing deteriorates, flue gas and fly ash leak out causing exposure to employees. At this point in the system the gas has not gone through any of the pollution control devices so it contains unabated amounts of SO_2, NOx, ash, etc.

Q. What are the advantages of a balanced draft boiler?

A. The advantage of a balanced draft boiler is that any breach in the casing causes air to leak into the boiler. This system eliminates both employee exposure to the boiler flue gas and secondary emissions to the atmosphere. This design also allows operators to open inspection doors and visually inspect the various heat transfer surfaces which allows for optimum soot blowing and the most efficient use of fuel.

Q. Did Public Service of New Mexico ("PNM") make any representations to TEP that BD was a necessary to comply with any applicable environmental requirements?

A. Yes. PNM made representations to TEP that BD was required to comply with the Title V air permit. As part of the October 24, 2013 Unit 1 BD capital budget approval,[3] PNM states the following work justification: "The project includes the installation of selective non-catalytic reduction (SNCR) technology to comply with the New Mexico Revised SIP, approved by the NM EIB on September 5, 2013. In addition, to comply with the Title V air permit, the unit will switch to a balanced draft configuration."

Q. Why was it ultimately decided to install balanced draft on San Juan Unit 1?

A. The decision to install balanced draft on San Juan Unit 1 was due to the fact that it was a requirement within the plant's air quality permit issued by the New Mexico Department

[3] See **Exhibit MCM-R-1** attached to my Rebuttal Testimony.

of Environmental Quality. The alternative would have been not to proceed with BD, which would have resulted in shutting down the unit given that it was required by the permit. Shutting the unit down would have triggered both "take or pay fuel" penalties and the need to remove the plant from service (which would increase the costs to decommission the unit). TEP would also be required to replace this baseload resource with a short lead time to acquire appropriate replacement resources, tramsmission capacity, etc.. These costs exceed the cost of installing balanced draft. Moreover, as described above the balanced draft system provides significant safety, health and environmental improvements.

III. Overhaul Averaging.

Q. Was it suggested that the time period that overhaul expenses are averaged over be changed?

A. Yes, Staff suggested the the overhaul averaging period be reduced from 8 years to 4 years, even though Staff had recommended an 8 year period in the last TEP rate case (which was subsequently incorporated as part of the settlement on revenue requirement).[4]

Q. Is four years an appropriate period a time to average overhaul expenses?

A. No, overhauls very from minor outages of a few weeks to major outages that can be six weeks or longer. The difference in outage scope and duration is usually driven by the turbine and generator requirements. Typically steam turbine valves are overhauled every 3 to 4 years, HP (high pressure) turbines every 6 to 8 years, LP (low pressure) turbines typically 9 to 12 years and generators typically 8 to 12 years. The combustion turbines have a nine year cycle for overhauls: the third year is a hot gas path overhaul, the sixth year is another hot gas path overhaul and the ninth year is a major overhaul of the hot gas

[4] See Direct Revenue Requirement Testimony of Staff Witness McGarry, page 7:1-6.

path and the compressor. These overhauls - and related outage frequencies - could vary by plus or minus a year due to the number of actual starts or hours of operation. The expense for each type of overhaul is very different. To actually obtain an average that accurately reflects the overhaul cycles and costs, an average of costs over ten years should be used.

Q. Does this conclude your testimony?

A. Yes it does.

Exhibit MCM – R – 1

ORIGINAL

SAN JUAN GENERATING STATION
CAPITAL BUDGET ITEM

Project Title: Unit 1 Revised SIP Compliance **Date:** 09/30/13

Project Manager:	Mitchell, David	CBI NO.:	13-60	Work Order No:	761-Y0060967
Project Start Date:	11/01/13	Budget Year:	2013	Retirement Order No:	761-Y0060986
Est Completion Date:	04/01/16	Outage Related:	Yes	Funding Project No:	761-21912
Est In-Service Date:	01/31/16	Outage Begins:	February	Original/Rev No:	Original

Description of Work/Justification:

The project includes the installation of selective non-catalytic reduction (SNCR) technology to comply with the New Mexico Revised SIP, approved by the NM EIB on September 5, 2013. In addition, to comply with the Title V air permit, the unit will switch to a balanced draft configuration. Component installation includes VFDs, ESP bypass duct, urea storage and distribution system and ash handling at the baghouse fabric filter system. Costs are estimated based on S&L submittal #31805D; issued Aug 7, 2013. Common costs for the project have been apportioned between Unit 1 and Unit 4 based on MWs

Environmental Compliance Review?	No				
DCS Review Required?	No	Completed?	N/A	If no, explain	To be completed at final design review
NERC Compliance Review Required?	No	Completed?	N/A	If no, explain	To be completed at final design review

Cost Breakdown	Retirement Order Removal	Work Order Installation
PNM Labor		$1,100,500
Material	$43,242	$17,958,408
Contract	$277,470	$50,279,090
A&G Loads	$3,200	$700,000
AFUDC		$1,242,651
TOTAL	$323,912	$71,280,647
PROJECT TOTAL	$71,604,559	

Capital Budget Item Cash Flow

	Removal Cost (RO)		Installation Cost (WO)			
	2014	2015	2013	2014	2015	2016
Jan		$20,000		$225,891	$889,059	$1,101,006
Feb		$23,242		$355,584	$15,330,455	$1,103,022
Mar		$280,670		$158,595	$17,361,691	$874,279
Apr				$459,983	$17,394,916	
May				$157,343	$1,212,678	
Jun				$107,442	$1,215,186	
Jul				$208,352	$1,217,702	
Aug				$134,683	$1,220,228	
Sep				$187,319	$1,222,764	
Oct				$1,209,304	$1,225,309	
Nov			$458,666	$1,345,560	$1,227,864	
Dec			$708,553	$1,738,783	$1,230,429	
Total	$0	$323,912	$1,167,219	$8,286,839	$60,748,282	$3,078,307
	$323,912		$71,280,647			
AFUDC			$0	$59,507	$1,174,282	$8,862

Authorizations

	Per Cent	Amount	Signature	Date
PNM	50.00%	$36,423,605		10-24-2013
TEP	50.00%	$35,180,954		10-24-13
TOTAL	100.00%	$71,604,559	Note: AFUDC applies to PNM Share only	

Recommended By: [signature] Date: 01/29/2014

Authorized By: (signed above) Date:

Exec. Sign.: (signed above) Date:

In-Service date:

Signed off by:

Proj Complete date:

Signed off by:

Rebuttal Testimony of

Carmine A. Tilghman

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

REBUTTAL TESTIMONY OF CARMINE A. TILGHMAN

ON BEHALF OF

OF TUCSON ELECTRIC POWER COMPANY

JULY 25, 2016

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Carmine A. Tilghman and my business address is 88 East Broadway, Tucson, Arizona, 85702.

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. My Rebuttal Testimony is filed on behalf of Tucson Electric Power Company ("TEP").

Q. Did you file Direct Testimony in this proceeding?

A. Yes, I did.

Q. Which Commission Staff and/or Intervenor testimony do you address in your Rebuttal Testimony?

A. I will primarily be addressing comments made by RUCO witness Huber, Solon witness Seibel, and Vote Solar witness Kobor.

To the extent I have not addressed other positions taken by Intervenors in their testimonies, it should not be taken as agreeing with or supporting these positions, and I reserve the right to discuss those issues as they arise during the course of this proceeding.

II. REBUTTAL TO RUCO WITNESS HUBER.

Q. What issues does the Company have with Mr. Huber's testimony regarding the proposed renewable credit rate?

A. Mr. Huber's proposals would not result in the most cost-effective solutions for TEP ratepayers. He argues that our customers will not be able to understand basic

import/export concepts, but offers only speculation to support his thesis. Additionally, while Mr. Huber believes the Company's proposal is too complicated, he then proposes multiple rate design structures that are far more complicated than the methodology the Company has proposed.

While Mr. Huber believes our customers cannot grasp the concept that "any exported energy will be paid at a different price", he proposes to use crediting mechanisms such as three part rates with on and off peak volumetric energy rates and monthly net metering; a buy all/sell all option where the credit rate adjusts annually; and two part rate structures with on and off peak volumetric rates, monthly net metering, and hourly export fees.

It appears from Mr. Huber's testimony that he believes the Company should not utilize all available alternatives for procuring the most cost-effective renewable resources. Whether or not the Company receives a Power Purchase Agreement ("PPA") that is subsidized by the developer, or adds-on to an existing array, is irrelevant. The point is that TEP's residential customers – the group that RUCO represents – should benefit from TEP using the most cost-effective resources available. The Company fails to see how non-DG residential customers benefit if DG customers are compensated at a rate above that of the most cost-effective available resource.

Q. Would implementing Mr. Huber's options be expensive?

A. Yes it would. It is my understanding that implementing all four of them would likely involve significant expense and some substantial changes to TEP's billing system.

Q. Mr. Huber suggests that the export rate TEP is proposing (the renewable credit rider) would be "ever-changing", which would make it difficult for customers to understand. What is your response?

A. I believe our RCR proposal would be less difficult to understand than RUCO's four different net metering options – one of which includes multiple levels of tranches that customers would presumably have to keep track of to know what their export rate would be at a particular time. However, as was the case in the UNS Electric rate case, we are willing to consider more stable options. For example, the export cost could be fixed for a set period of time at the RCR rate for the year the solar system is installed. The key point is that our non-DG customers should not be forced to pay the current high rate, when much less expensive wholesale solar options exist. Further, selling power to a utility is a wholesale transaction, and should be made at wholesale rate.

Q. Do you agree with Mr. Huber's calculations in his Direct Testimony?

A. No. I would like to focus on Mr. Huber's overstated capacity value in his value of DG calculation. While I appreciate his effort to calculate a "capacity value" for distributed generation, Mr. Huber attempts to justify an overstated grid value for DG. Any valid analysis of a generating resource, particularly DG, must acknowledge the operational differences between a unit's ability to provide operational capacity (direct response, reserves, etc.) and its Effective Load Carrying Capability ("ELCC"), which is the approximate or average percentage of the systems' nameplate capacity that can be expected during peak. For example, a 100 MW solar facility may provide an average of 30 MW during the system's peak hour, resulting in an ELCC of 30%. However, this is NOT the same as a conventional 100 MW generator providing 30 MW. The conventional generator can receive system control signals, provide regulation up and down, frequency response, volt/VAR support, and respond to system disturbances. In my experience, the differences between a generators' capacity value and its ELCC are often confused by analysts who lack practical operational knowledge of grid management and operations. This results in an overstated value for a capacity savings based on the inaccurate assumption that the installation of an intermittent resource is the equivalent of a firm

generating resource. Mr. Huber and certain other Intervenors continue to claim that DG systems will provide future grid management benefits without fully understanding grid operations and grid management.

In short, Mr. Huber's own arguments are contradictory in pursuit of a higher DG payment value when RUCO knows that TEP can procure renewable energy from a utility scale facility tied to our distribution system for far less. Even if the Company agreed with Mr. Huber's assessment of all of the supposed forward benefits (which the Company does not), how does it benefit residential customers to pay a higher amount for solar energy from a rooftop DG system than the cost of solar energy TEP can procure through a large scale PPA tied to its distribution system?

Q. What is the problem with valuing intermittent resources the way RUCO and Mr. Huber suggest?

A. While it can be argued that intermittent resources provide some level of ELCC on a short term operational basis, this comparison must include the acknowledgement that a presumed capacity value through a planning process DOES NOT provide operational capacity at the time the load is actually served. More to the point, to meet its obligation to serve, a utility does not and cannot: (1) assume that solar will always provide 30% of its rated capacity during peak; (2) assume that solar will provide necessary ancillary services; and (3) equate intermittent resources with a firm, controllable and available resource, when the utility has no direct control over the intermittent resource.

III. REBUTTAL TO SOLON WITNESS SEIBEL.

Q. What issues do you have with Solon witness Seibel's testimony?

A. First and foremost, I disagree with Mr. Seibel's characterization of the June 1, 2015 proposal for net metering changes as being retroactive. As with all industry participants whose business model relies on significant subsidies that burden non-participating utility customers, Solon is simply attempting to protect its own business interests at the expense of TEP's non-DG customers. Even given sufficient notice in early March of 2015 that the Company would be proposing these specific changes, and having approximately 2 ½ months to make even a modest attempt to restructure their development model, Solon has chosen to simply demand that the Commission view the proposal as "retroactive." Mr. Seibel attempts to equate the Company's voluntary proposal to withdraw the original net metering application and include it in the rate case with a hard and fast rule that it must no longer be considered. In fact, the Company's filing stated that TEP would withdraw its application and specifically include the same provisions in its rate case application.

Q. Is the proposed grandfathering date of June 1, 2015, equivalent to retroactive ratemaking?

A. No it is not. That date only identifies which customers would go onto the new R-15 rider *as of the date TEP's rates would go into effect.* TEP is not seeking to reach back to put non-grandfathered DG customers on a new tariff as though it had been effective June 1, 2015 and true-up the difference. Rather, that date gives customers notice as to which DG customers would be subject to the new rider after new rates go into effect – versus which DG customers would have the luxury of staying on the current R-4 Rider through May 31, 2035. Grandfathering is the exception, not the rule. Typically, all customers would go onto the new rider upon Commission approval.

Q. Does Mr. Seibel agree that the grandfathering date and the effective date are different?

A. Yes. In response to TEP data request 2.10, he agreed that "there is a difference between the grandfathering date (which determines which customers are exempt from a tariff) and the effective date of the tariff."

Q. Was Mr. Seibel able to provide any evidence that TEP proposed June 1, 2015 as the effective date?

A. In response to TEP data request 2.11, Mr. Seibel cited page 8, lines 13-17 of the Direct Testimony of Dallas Dukes, which refers to "Rider R-15 (NM-PRS), Post June 1, 2015". This is simply the name of the proposed tariff. The reference to "Post June 1, 2015" is a reference to the grandfathering date. TEP has <u>never</u> advocated for a 2015 effective date for this tariff. The new tariff will apply to non-grandfathered customers on the same date that all other rates from this case take effect. Mr. Seibel's inflammatory rhetoric about "retroactive rates" has no basis in fact.

Q. Have customers been notified that if they apply for DG after the June 1 cutoff date, they may be subject to a new net metering tariff rider?

A. Yes. TEP provided notice to customers of the proposed changes and cutoff date, and the customer has acknowledged the possibility that they may be subject to rate design changes, so that potential DG customers had the requisite information to make a decision at the time they choose to go ahead with installing DG, contrary to what Mr. Seibel implies on page 12 of his Direct Testimony.

Q. Does Attachment A to Mr. Seibel's testimony (TEP's DG interconnection application) "threaten" customers as he describes it on page 13 of his direct testimony?

A. No, it does not. While Mr. Seibel's characterization of providing our customers' with truthful and accurate information as a threat is consistent with the rhetoric and tone throughout his testimony, it is inaccurate. As we have repeatedly explained, we are not "taking net metering away". We are simply adjusting the value of the export rate to be consistent with alternative options. But notifying customers is not a threat, and requiring customers to sign an acknowledgement is also exactly what the Commission and its Staff expected from us to do, so that customer and Company are on the same page as to the customer being informed of this potential change.

Specifically, while Mr. Seibel states, on page 14 of his Direct Testimony, that *"it is deeply disturbing for a regulated utility to distribute, and require a customer to sign, a disclaimer acknowledging the possibility of retroactive rates or other unexplained changes*", he fails to mention that the Company has been has been issuing and requiring these documents in some form since February 2014, at the request of the Commission and Staff following a similar order to Arizona Public Service Company (APS). Moreover, the Company was ordered by the Commission in August 2015 to modify the existing disclaimer and that disclaimer was supported by Staff, Vote Solar, RUCO, ASDA and ARiSEIA.[1]

Q. Are you trying to usurp the Commission's authority, Mr. Tilghman, as Mr. Seibel implies TEP is doing on page 18 of his Direct Testimony?

A. No, that is another misstatement by Mr. Seibel. If the Commission approves a grandfathering date different than what the Company proposes, we will honor that. TEP, however, believes that the June 1, 2015, is reasonable, fair and amply supported in the record. Additionally, since this case will likely not be resolved until the end of 2016 at the earliest, TEP has given customers' well-over-one-year's notice that net metering

[1] *See* Decision No. 75224 (August 26, 2015), Findings of Fact 14-25.

changes could occur. So TEP has, in fact, done exactly what Mr. Seibel recommends the Commission order TEP to do on page 18 of his Direct Testimony.

Q. What other concerns do you have with Mr. Seibel's testimony?

A. Contrary to Mr. Seibel's implication at page 10, the idea that net metering changes were and are needed is not new, and has been a topic of discussion for some time. While Mr. Seibel boasts of a long record of "financial analytics" and "solar production modeling", at the same time he would have the Commission believe that Solon is incapable of performing anything more complicated than a standard "net zero" performance calculation. In actuality, traditional analytics for solar production and financial modeling under an annual net metering policy is the equivalent of a high school math exercise. It is puzzling that solar industry participants such as Solon, who claim to be industry experts in performing financial analytics and solar production modeling, are unable to provide a customer with a more accurate representation of their energy savings.

Q. How do you respond to Mr. Seibel's assertion that solar interconnection applications "came to a screeching halt" as he states on page 13 of his Direct Testimony?

Mr. Seibel's claim is simply wrong. As the Company has provided through numerous data requests in various proceedings, TEP continued to receive applications at a steady rate after June 1, 2015. Indeed, the application rate now exceeds the application rate prior to the Company's March 25, 2015 original proposal to modify changes to net metering.[2]

[2] On March 25, 2015, TEP filed an application with the Commission (Docket No. E-01933A-15-0100) requesting changes to its net metering tariff. TEP subsequently withdrew its application on June 19, 2015 with the intent of seeking net metering modifications in this rate case docket.

IV. REBUTTAL TO VOTE SOLAR WITNESS KOBOR.

Q. What issues does the Company have with Vote Solar witness Kobor's testimony?

A. While the Company has many issues with witness Kobor's testimony, I will focus my comments on her testimony regarding the impacts of DG on the Company's system and associated compensation under the proposed Renewable Credit Rate. I reserve the right to further elaborate on any disagreements regarding Ms. Kobor's testimony through direct examination on the witness stand.

Q. Specifically what does the Company take issue with regarding Ms. Kobor's testimony on DG system impacts and the Renewable Credit Rate?

A. Ms. Kobor indicates that her "analysis" does not show that TEP has established that DG causes significant grid impacts, and therefore no changes to DG compensation or NEM is justified. However, while the Company is unsure what Ms. Kobor would consider a "significant grid impact", the Company—and the utility and electrical industry at large—has shown that there are definitive operational detriments to the integration of variable generation on the grid, including (but not limited to) distributed generation. Ms. Kobor's statement that the Company relies on national and regional studies rather than specific TEP system studies demonstrates her lack of operational understanding of grid operations and the need to perform "repetitive" studies. For the record, TEP has performed certain individual system studies, and continues to perform studies on specific circuits. Most notably, the Company's Los Reales Feeder circuit study has shown significant phase imbalance and backflow due to distributed generation resources on the circuit. Results of these studies confirm what the regional and national studies have previously concluded.

In addition to Ms. Kobor's comments regarding the impacts of DG on TEP's system, Ms. Kobor continues to attempt to disassociate DG solar and its purported "value" from the

lower cost that a utility can realize through procurement of a nearly identical resource, namely a utility scale solar facility. Ms. Kobor would have the Commission - and the communities that TEP serves - believe that the purported benefits of a DG system should be priced higher and valued separately, than a community based, utility scale facility that provides solar energy to a broader base of customers at a lower cost. The Company disagrees with Ms. Kobor and Vote Solar's opinion that TEP ratepayers should be forced to pay a higher rate for the benefits of renewable energy than what is available to the Company through larger utility scale facilities.

Q. Do you agree with Ms. Kobor's argument, specifically on page 22 of her direct testimony, that the problem is not large enough to warrant any changes to address the cost-shift due to DG systems?

A. No. Ms. Kobor simply points to a snapshot in time to justify her position. But the fact is that the cost-shift due to DG is a growing problem. Assuming that her conclusion is true (and we are not conceding that at this time) she ignores the fact that the increasing number of DG installations will result in a decline in retail sales in excess of 6%. The Commission has already found that a cost shift exists with non-DG customers subsidizing DG customers. Vote Solar and other parties stated that the rate case is the appropriate forum to address this problem; so now is the time to address this problem while it is at a manageable level. I do not believe it is appropriate to wait until there is a certain level of DG penetration in the market before the Commission addresses an acknowledged problem.

Q. Ms. Kobor insinuates that TEP's argument is based on "hypothetical NEM customers who size their system to offset 100% of annual load." What is your response?

A. This is not a hypothetical situation. We know from actual experience that DG customers have systems designed to offset nearly 100% of annual load. Indeed, the Commission's net metering rules provide for customers sizing their systems up to 125% of total connected load. The solar industry utilizes these rules to their fullest advantage to design systems to provide as close to an annual net-zero effect as possible, and that is reflected in the applications we are seeing and the impacts TEP is experiencing on its system.

Q. Ms. Kobor dismisses the cost shift as "an inherent side effect of rate design." Does that mean we should simply ignore the problem?

A. No. Although there are policy reasons to justify certain cost shifts that occur, such as when low-income customers are subsidized, rate design should be fixed if there are inequitable impacts on customers such as those caused by DG. Differential rate treatment is justified here; it is not unduly discriminatory to reflect that DG customers have essentially become partial-requirements customers.

Q. Is there anything in the net metering rules that prohibits the Company's proposal?

A. No. Changes to the net metering tariff are fully within the Commission's purview, and to the extent TEP needs a waiver from the rules to implement its proposal, it is seeking such a waiver – and is doing so within a full rate case, exactly as we were advised to do. Further, the solar industry appears to be under the misconception that exported excess energy *must* be credited at the retail rate to be net metering. That is not accurate.

The Arizona Administrative Code, under Title 14, Chapter 2, Article 23 under R14-2-2303 defines Net Metering as *"service to an Electric Utility Customer under which electric energy generated by or on behalf of that Electric Utility Customer from a Net Metering Facility and delivered to the Utility's local distribution facilities may be used to offset electric energy provided by the Electric Utility to the Electric Utility Customer*

during the applicable billing period." While the definition of net metering clearly allows for the use of a full retail credit for energy, the words *"may be used to offset electric energy"* also would apply to a credit paid for exported DG energy. It could just as easily be argued that the offset to *"electric energy"* is the energy only component of the utility's rate, or an equivalent solar energy rate.

The Company's proposal does not eliminate net metering; it simply values excess energy at an export rate more reflective of actual avoided cost. But it is still a credit that offsets DG customer bills. Further, DG customers receive the full retail rate offset for energy that they consume onsite from their PV facilities. Ms. Kobor's implication that the Company's proposal violates net metering is not accurate.

Q. Please address Ms. Kobor's comments that a utility-scale facility is not a fair proxy for distributed generation, specifically on pages 27-28 of her Direct Testimony.

A. First, Ms. Kobor acknowledges that utility-scale resources are essentially less expensive than DG. But then she offers a convoluted argument about conflating the issue of utility-scale pricing versus distributed-scale pricing from a utility perspective. She is basically asking the Commission to ignore the elephant in the room: that a utility like TEP could acquire renewable energy from utility-scale resources at a lower price than from DG. Further, she adds that the "non-participating ratepayer will be generally indifferent to and unaware of" where the electrons come from. While the non-participating ratepayer may be indifferent to where the electrons come from, they are NOT indifferent about having to pay 2-3 times more for energy from a distributed generation resource being paid under net metering.

TEP must consider cost impacts to its customers and typically must seek to acquire power at the most cost-effective level. While the Commission may decide certain societal

policies justify the use of a more expensive resource, they should do so with the complete knowledge of lower cost alternatives and the impacts to the ratepayers.

Q. Ms. Kobor states that TEP is ignoring many key benefits provided by DG that are not provided by utility-scale renewables, such as higher generation capacity and potentially greater avoided distributed costs and grid services. Do you agree?

A. Ms. Kobor again ignores the unplanned nature of how DG is deployed throughout TEP's service territory. Just because DG is "geographically diverse" does not mean it is going to provide these purported benefits that equate to higher capacity value and potentially greater avoided distribution costs. Also, she ignores the infrastructure improvements TEP must make to accommodate the unplanned nature of DG installations.

As I have stated and based on my experience observing how the growth of DG impacts TEP's grid, the random way by which DG systems are added onto TEP's system will necessitate measures and improvements to address the stability issues caused by DG proliferation. These measures and improvements have a cost. If renewable energy systems were placed strategically throughout TEP's service territory, the need for additional improvements of this type could perhaps be reduced somewhat. But that is not the case with DG and the positions perpetuated by Vote Solar and others. Moreover, the need for ancillary services (such as voltage or frequency control) will increase with increased DG and intermittent resource installations.

In contrast, alternative renewable resources strategically placed would lessen such adverse impacts. Utility-scale renewables, for example, are planned and therefore provide TEP with the opportunity to strategize where they might optimally provide value to it and its system. Ms. Kobor fails to recognize the undisputable advantage of a larger scale facility interconnected to the utility's three-phase system (through a detailed

interconnection study) versus the randomly-sited DG system that creates phase imbalances and reverse flows.

Q. Ms. Kobor, on page 32 of her direct testimony, indicates three problems with TEP's proposed renewable credit rate. How do you respond?

A. I have already discussed how the Renewable Credit Rate does not violate Commission rules, especially since the Company is seeking the appropriate waiver in the full rate case. Further, Ms. Kobor assumes that the Commission would have no authority over the RCR once established. TEP would work closely with Utilities Division Staff to demonstrate that any future change in the RCR is appropriate and justified. That leaves Ms. Kobor's first argument – that the RCR does not approximate the value of DG. As I have stated and demonstrated before, utility-scale solar and other renewables provide equivalent benefits as DG, with the added benefit of being planned. Ms. Kobor rests her opinions on abstract study work from other jurisdictions that make generous assumptions about the value of DG. We base our conclusions on actual experience.

The solar industry advocates, such as Ms. Kobor and Vote Solar, have consistently failed throughout this year's various Commission proceedings (UNS Electric rate case, Cost and Value of Distributed Solar hearings, and now the TEP rate case) to explain why a utility's ratepayers should be required to pay 2-3 times for renewable energy than what is available to them form a utility scale facility.

V. <u>RESPONSE TO REQUEST FOR REST PLAN OF ADMINISTRATION.</u>

Q. Are there any other issues that you would like to address in this testimony?

A. Yes. The Direct Rate Design Testimony of Eric Van Epps recommends that the Company file a Plan of Administration ("POA") for its REST adjustor consistent with the POA

filed for UNS Electric and that the POA "incorporate all existing pertinent Commission decisions." The Company will provide a POA prior to the hearing in this matter.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Rebuttal Testimony of

Dallas J. Dukes

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-1933A-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

Rebuttal Testimony of

Dallas J Dukes

on Behalf of

TUCSON ELECTRIC POWER COMPANY

JULY 25, 2016

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Dallas J. Dukes and my business address is 88 East Broadway, Tucson, Arizona, 85702.

Q. Did you file Direct Testimony in this proceeding?

A. Yes.

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. I am filing Rebuttal Testimony on behalf of Tucson Electric Power Company. ("TEP" or the "Company").

Q. How is your Rebuttal Testimony organized?

A. My testimony is organized as follows.

II. Proposed Reduction in Non-Fuel Revenue Requirement

III. Rate Design

IV. Net Metering Tariff

V. Economic Development Rider

II. PROPOSED REDUCTIONS IN NON-FUEL REVENUE REQUIREMENT.

A. Reduction in Non-Fuel Revenue Increase.

Q. Is TEP reducing its requested non-fuel revenue increase from the $109.5 million requested in its Application?

A. Yes, TEP is reducing its requested non-fuel revenue increase from $109.5 million to $100.6 million over test year adjusted non-fuel revenues. However, that $9.0 million non-fuel reduction does not provide a complete understanding of the reduced request and the net impact to customers being proposed by TEP in this Rebuttal filing. In our initial request we proposed a total retail revenue requirement of $1,050.6 million, in our Rebuttal filing we are requesting a total retail revenue requirement of $1,026.9 million—an overall *reduction* of $23.7 million. This is a 21.6% reduction in the originally requested increase to customers. The table below summarizes these changes in more detail.

Table 1: Requested Revenue Revenue Requirement (Thousands of Dollars)

As Filed Position	**$1,050,566**	
Rate Base Adjustments		**Rebuttal Testimony Sponsor**
Wholesale Jurisdiction (Demand and Energy)	(3,503)	Michael Sheehan
Sundt & SJ M&S	76	David J. Lewis
ADIT Bonus Depreciation	(1,471)	Frank P. Marino
Working Capital	483	David J. Lewis
Subtotal of Adjustments	(4,415)	
Rate of Return Adjustments		
Decrease Allowed ROE from 10.35% to 10%	(5,907)	Ann E. Bulkley
Revenue & Expense Adjustments		
Wholesale Jurisdiction (Demand and Energy)	(4,093)	Michael Sheehan
Transmission Expense	(1,748)	David J. Lewis
Credit Card Fees	(3,483)	Denise A. Smith
Depreciation and Amortization	(2,948)	David J. Lewis
Lime Expense	(1,616)	David J. Lewis
Overhaul & Outages	559	David J. Lewis
Compensation and Benefit Adjustments	(775)	Frank P. Marino
Sundt & SJ M&S	244	David J. Lewis
Reduction of Base Cost of Fuel	(14,778)	Michael Sheehan
Springerville Unit 1 Non-Fuel Expense	15,244	Kentton C. Grant
Other	47	
Subtotal of Adjustments	(13,347)	
Rebuttal Revenue Requirement	**$1,026,897**	
Proposed Reduction	**($23,669)**	

Q. Please explain why the non-fuel revenue increase is only decreasing by $9.0 million, but the retail revenue requirement is decreasing by $23.7 million?

A. The Company initially requested to recover through the PPFAC non-fuel operating costs associated with the 50.5% of Springerville Unit 1 not owned by the Company but that would be providing service to retail customers. The amount proposed to be recovered was approximately $16 million annually, which when jurisdictionally allocated is

approximately $15 million. As discussed in the Rebuttal Testimony of Kentton C. Grant, the Company is now requesting to recover those costs through non-fuel rates, not the PPFAC. The request to recover these costs as an operating cost and not as a component of the PPFAC, increases the Company's requested non-fuel revenue increase, but correspondingly decreases the fuel revenues requested.

III. RATE DESIGN.

Q. Is the Company making any significant changes to the rate design proposals in Direct Testimony?

A. No, however we are accepting Staff's proposals regarding the basic service charge as described below.

Q. Please briefly summarize the key changes the Company initially proposed for the Residential and Small General Service ("SGS") customer classes.

A. In its Application, the Company's proposed to: (i) to increase the basic service charge for residential customers from $10 to $20; for the SGS class from $15.50 to $30.00 for single phase service; (ii) eliminate the third and fourth rate tiers for volumetric Delivery Services-Energy charges; (iii) implement mandatory three-part rates for all partial requirement residential and SGS customers who installed distributed generation after June 1, 2015 (collectively, "New DG Customers"); and (iv) provide optional three-part rates for all other residential and SGS customers.

Q. What are the primary reasons for updating TEP's rate design?

A. In this proceeding, the Company is attempting to gradually and fairly modify its rates to (i) reduce intra-class subsidization, (ii) promote fairness and recover costs from cost causers, (iii) provide flexibility to accommodate changing customer usage patterns, (iv)

move toward rate structures that encourage the integration of new energy technologies on the electric system, thus promoting more efficient use of the electric system, and (iv) create a sustainable rate structure that ensures that the Company can continue delivering safe, reliable and affordable electric services for the benefit of all our customers.

A. <u>Basic Service Charge.</u>

Q. Has the Company made any changes in its proposals as described above?

A. Yes. The Company is reducing the requested basic customer charges from $20 to $17 for the Residential class and from $30 to $27 for the SGS class, based on Staff's recommendations.[1]

Q. Why has the Company reduced its requested basic service charges for these classes?

A. The Company strongly believes that modernizing rate design in a manner that allows for more appropriate recovery of costs is an essential component of this rate case and that its proposals of $20 and $30 appropriately implements a portion of this goal. However, the Company recognizes that rate design changes are subject to impact consideration and gradualism. We appreciate Staff's recognition of the necessity of moving toward more equitable and cost based rates.

Q. Were there other parties to the proceeding that oppose the increasing of the basic service charges for these classes?

A. Yes.

[1] Direct Rate Design Testimony of Staff Witness Howard Solganick ("Solganick"), page 30:1, 31:4.

Q. In general, what were the arguments against increasing the basic service charge?

A. These arguments range from using a customer cost estimate methodology that only reflects a portion of actual customer costs, to misapplied policy arguments. Such arguments include claims that higher customer charges will adversely impact low income customers, that our requested basic service charge is too high and is not "common utility practice," or that the higher basic service charge will reduce investment in energy efficiency, and that fixed cost shouldn't be recovered through fixed charges.

Q. Please comment on why the Company disagrees with these assertions.

A. I am not going to attempt to respond to all of the interveners' assertions, however, Company witnesses, Dr. Overcast and Mr. Jones go into detailed explanations in their Rebuttal Testimonies as to why each of the interveners' arguments should **not** dissuade the Commission from allowing TEP to move toward a fairer and more equitable cost based rate structure to the benefit of its customers. As concluded by Staff's witness Solganick, regarding the basic service charge increase (emphasis added), "All residential Basic Service Charges should be $17.00 to **approximate** the Company's **costs**."[2] Rates are inequitable if they are not based on cost.

> Just and reasonable rates must reflect cost causation. Since the customer component of cost is the same for all customers in a properly designed rate class, setting the rate below the properly determined customer costs (discussed above including the minimum system classification) means that low use customers are subsidized by high use customers creating an inequity that is not justified except for social policy related to customers and only customers who have incomes that allow them to qualify as recipients of low income related services. Maintaining low customer charges based on the impact on low use customers assumes incorrectly that there is a correlation between low use and low income customers who qualify as low income customers with poverty status.[3]

[2] Solganick, page 30:1

[3] Rebuttal Testimony of Company Witness Dr. H. Edward Overcast ("Overcast Rebuttal"), page 24:10.

Q. What about the assertion that TEP's requested higher basic service charge deviates from common utility practice?

A. That is simply not true and blatantly ignores the data that is readily available to the contrary.

> As a practical matter the common utility practice has been to increase customer charges. In fact, there are about 1,000 electric utilities with residential customer charges equal to or greater than $20 per month[4] as proposed by TEP. On that basis alone the common practice that includes IOUs, Cooperatives and Municipal Utilities is to increase customer charges and to reflect customer costs in rates.[5]

Q. What about the assertion that the requested higher basic service charge will reduce the incentive to invest in energy efficiency?

A. The argument just doesn't hold up if one looks at the basic facts. Even with our proposed elimination of the third and fourth rate tiers as proposed by the Company, and with the originally proposed $20 basic service charge, 99.5% of the billed consumption (based on test year bill frequency data) would be billed at a higher per kWh rate. Let me say that another way, the Company's proposal only reduces the volumetric rate for ½% of the expected sales to customers. For a typical customer, their billed consumption will increase in the range of 6-14%. Under the Company's proposal, each additional kWh in the 501-1,000 range of kWh consumption will cost the Customer an additional 11.6 cents (excluding taxes and assessments). With present rates it would cost them an additional 10.2 cents. It's just misleading for any party to state that an incentive to reduce consumption will be diminished with TEP's proposed rate structure.

In addition, for parties that champion <u>increasing</u> the inequity of our rate structure brings into question the motives of these parties, especially those who in the same sections of

[4] Utility Rate Database, http://en.openei.org/wiki/Utility_Rate_Database .
[5] Overcast Rebuttal, page 32:7.

their testimonies argue that the Company's proposals will harm low-income customers. The bill frequency data for our actual low-income customers (not a statewide or national survey) show that less than 44% of all low income bills are under 500 kWh – which is equivalent to our non-low income customer group. In general, the distribution of usage levels for our low income is about the same as other residential customers. So these groups are arguing to add further unjustified cost recovery burdens on these higher usage customers – which include a significant proportion of our low-income customers. Company witness Dr. Overcast sums it up very succinctly in his Rebuttal testimony.

> As this statement notes higher energy charges result in uneconomic bypass including DG, DER and energy efficiency. By charging rates that exceed marginal cost even including plausible values for externalities, the RUCO proposal and indeed the proposals of all the opponents of the TEP customer charge increase are supporting a significant loss in social welfare to support their own end-use opportunities.[6]

Q. What about the assertion that it is a faulty premise to recover fixed cost through fixed charges?

A. Again, these types of assertions appear to be based, not in cost basis or sound economic theory, but in a results driven quest to push ever greater amounts of fixed cost recovery onto the higher usage customers. Not one of the parties proposing to recover greater amounts of fixed cost through volumetric rates is proposing to eliminate the inclining rate tiers or place a larger portion of those fixed cost recoveries into the first volumetric rate tier. Instead, they are proposing to unjustifiably increase the cost to the higher usage customers as compared to today's rates, thus increasing the inequities that exist in our current rate structure. As I stated in my Direct Testimony, we presently have just over 33% of our residential customers paying substantially more than their fair share of fixed cost and 66% of our customers paying less than their fair share of fixed cost. To argue

[6] Overcast Rebuttal, page 35:14.

that this inequitable situation should be exacerbated and to not put forth any proposals to at least make progress in addressing this issue is not in the public interest.

B. <u>Elimination of the Third and Fourth Rate Tiers.</u>

Q. Is the Company changing its proposal to remove the third and fourth rate tiers for volumetric delivery services-energy charges?

A. No. The Company and Staff[7] both recommend elimination of the third and fourth tiers.

Q. In general, what were the arguments against eliminating the third and fourth rate tiers for volumetric Delivery Services-Energy charges?

A. These arguments generally fell into three categories; elimination of the tiers will result in: (i.) a disproportionate impact to lower usage customers; (ii.) regressive rates; and (iii.) a weakening of the price signal to save energy.

Q. Does the Company agree with any of these assertions?

A. No, not at all.

Q. What about the assertion that elimination of these tiers will have a disproportionate impact on lower usage customers or that it's a regressive policy?

A. For these arguments to have any merit, one would have to assume that today's low customer charge with inverted block volumetric rate structures is fair and equitable to all of our customers. Because, with the exception of Staff, other parties are essentially arguing to retain the current structure or to actually place a greater unjustified cost burden on the higher energy using customers. The Company, through my testimony as well as

[7] Solganick, page 29:21-23.

the testimony of Mr. Jones and Dr. Overcast, have provided substantial evidence to refute this false assertion.

> The unequal treatment of customers who have the same costs but provide very different levels of revenue to recover those costs is a perfect demonstration of undue discrimination and that the current rates are no longer just and reasonable as the result of a combination of the net metering provisions and the current inverted block two-part rate with a low monthly basic customer charge. Essentially, the recovery of almost all of the fixed cost of service in volumetric charges results in undue discrimination when the customers in a class are no longer homogeneous.[8]

As I explained above, the Company's proposal is to move gradually toward more equitable cost recovery within the entire residential rate class. It is counter intuitive to argue that moving toward a more balanced and fair rate structure is "regressive." Again, that requires the assumption that; (i) the present rate structure is fairly balanced and/or equitable – which it is not of (ii) we are proposing to move toward a structure that puts a greater amount of cost recovery onto the lower usage customers than is fair and equitable – which we are not.

Next I want to address the assertion that the impact to lower usage customers is disproportionate or will adversely impact that group. This claim is only true if one ignores the plain facts that this group of customers is not presently paying the cost to serve them AND that you have to give that group a larger portion of any increase (or smaller portion of any decrease) to move toward equity. The dollar impacts on low usage customers can be illustrated with a simple example. The revised basic service charge increase is $7 or about 23 cents per day. Then if you assume that a low usage customer uses, on average 500 kWhs or less per month, and take our proposal to increase the first tier by 0.5 cents – at worst that is about 8 cents per day. So in total the increase we are

[8] Overcast Rebuttal, page 76:3.

asking for to make progress toward a more equitable rate structure is at worst about 31 cents per day or about $9.50 per month for a low usage customer. Of course, $10 per month could be substantial to a significant portion of these low usage customers, and TEP is not discounting that. However, to make any progress toward more equitable cost based rates we have to increase these lower usage bills greater than that of an average customer proportionately **(although these customers are still seeing a dollar increase that is less than the typical residential customer, as discussed in Mr. Jones' Rebuttal Testimony)**. TEP is requesting a justifiable rate increase to recover the cost to serve, and as such, all rates by class are going to go up.

> The issue of low-use customer impacts has been discussed above, but essentially the current rates and low customer charge are inequitable because they do not recover costs caused by low-use customers.[9]

Q. What about the assertion that elimination of the third and fourth tiers will reduce incentives for customers to conserve?

A. I've already discussed this previously in my testimony – this is simply a false statement. TEP is proposing to increase the cost per kWh consumed by our customers thereby *increasing* the incentive to conserve – to assert anything else is just incorrect.

C. Three-Part Rates for all Partial Requirement Residential and Small General Service Customers.

Q. To make it clear, are all of TEP's proposed rate design changes simply to address partial requirement customers, such as solar DG customers?

A. No, regardless of the misguided accusations made by certain other parties, TEP is not designing rates with the sole purpose of eliminating solar DG installations in our service

[9] Overcast Rebuttal, page 34:5.

territory, or reducing the incentive for customers to conserve or limiting the ability of customers to reduce their bills through investment in new appliances, technology or simply through behavioral changes. TEP is attempting to gradually address the totality of inequitable and uneconomic issues caused by recovering the vast majority of our fixed system cost through two-part, inverted block volumetric pricing with a low basic service charge. In short, we are trying to gradually shift towards an overall rate design that more accurately reflects cost causation.

However, our proposal to implement three-part rates for new DG customers is meant to address the unique subsidization issues related to serving them with two-part rate design and net-metering. This is discussed extensively in the Rebuttal Testimony of Company witnesses Dr. Overcast, and Mr. Jones. In addition, the bill impacts of these proposed changes are discussed in the Rebuttal Testimony of Company Witness Mr. Bachmeier.

> All of this evidence suggests that with a two part rate and net metering with banking can never result in just and reasonable rates for partial requirement DG customers. The only possible alternative to treat partial requirements, DG customers equitably is a separate rate class with a three-part rate.[10]

Q. What are the general arguments made by parties in this proceeding against TEP requesting that partial requirements/DG customers being limited to three-part rate options?

A. These arguments fall into three general categories (i.) DG customers (partial requirement customers) are an insignificant portion of sales and revenue loss and that the Company recovers the lost revenue through the LFCR process, (ii.) DG customers are not different than full requirement customers, and (iii.) it's discriminatory to treat them differently than standard full requirement customers and the rules don't allow it.

[10] Overcast Rebuttal, page 75:2.

Q. Please address the assertions that DG customers (partial requirements customers) are an insignificant portion of sales and revenue loss and that the Company recovers the lost revenue through the LFCR process.

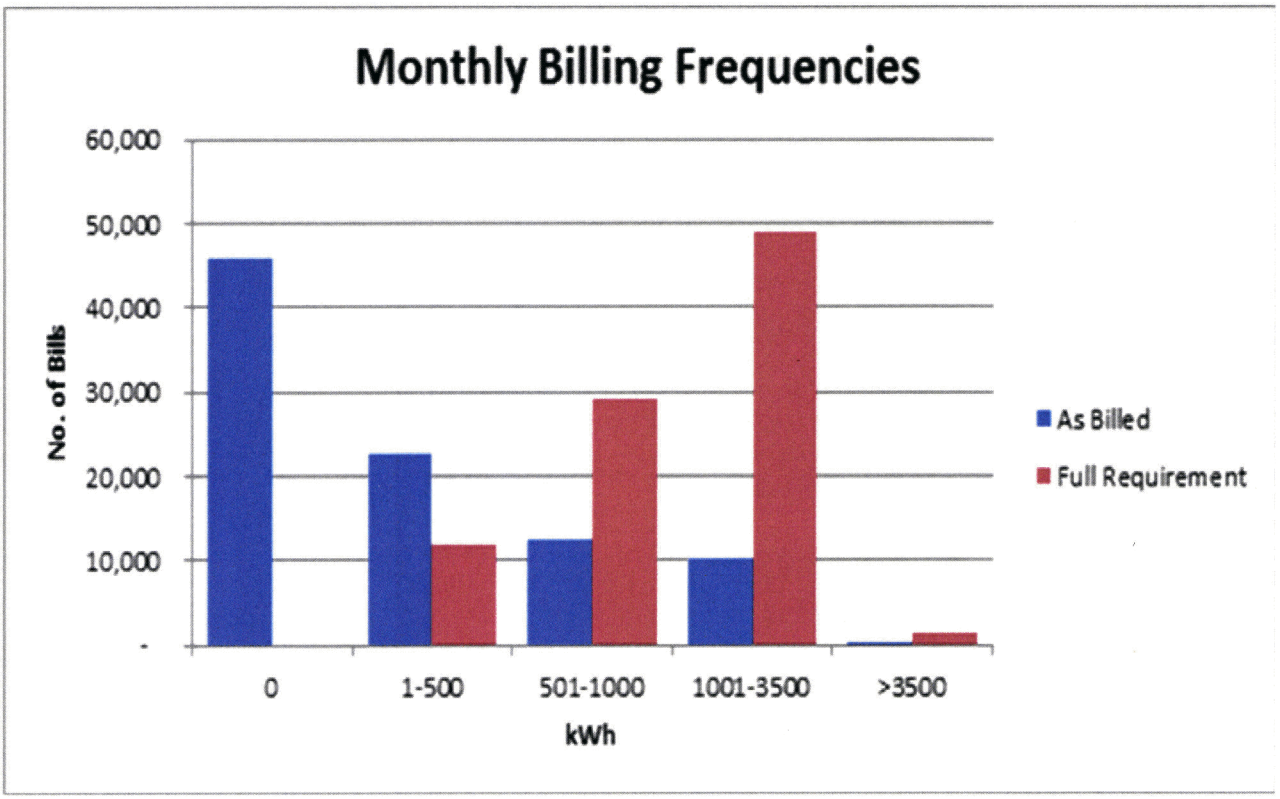
A. The major flaw in this argument is that it ignores key facts: (i) the number of DG applications and thus the magnitude of the transfer of cost to other customers is growing rapidly[11] – so to ignore the issue now, because it's deemed fairly small (by the intervening parties) at this time, is just poor rate making policy and just adds to the cost burden of other non-DG customers and to the difficulty of addressing it later and (ii) the cost burden is not small or insignificant; the transfer of cost recovery is substantial and growing, as pointed out in the Rebuttal Testimony of Mr. Jones. The transfer of cost for the 12,000 current NEM customers is approaching the $9 million range – that is not an insignificant amount and will continue to grow if rate design is not meaningfully updated in this proceeding.

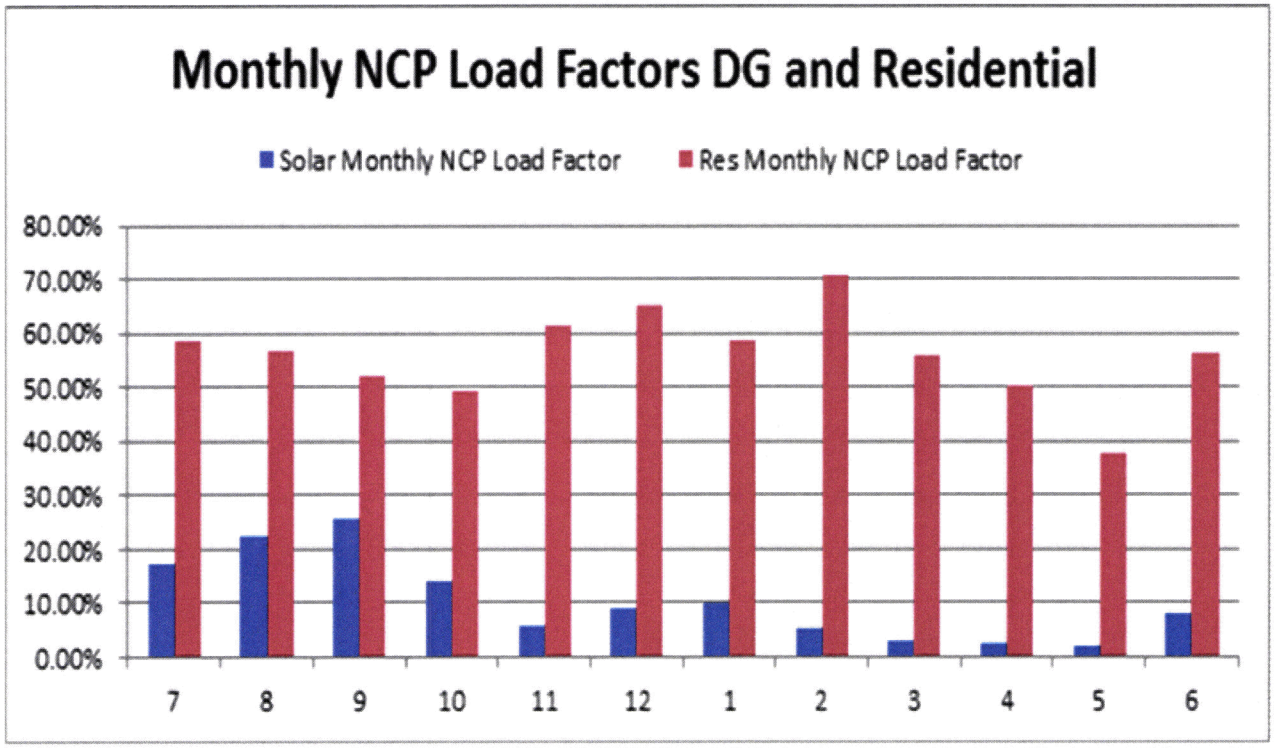
Q. Please address the assertions that DG customers (partial requirement customers) are no different than standard full requirement customers.

A. This is just a completely false assertion and blatantly ignores the clear facts and load profiles; to claim that a customer that self generates a portion of their own electricity is the same as a standard full requirements customer is baffling. This claim is refuted extensively in the Rebuttal Testimony of Dr. Overcast, but let me just share a couple of the major facts. Below are two charts provided by Dr. Overcast in his Rebuttal Testimony based on the actual data of TEP's customers. The first clearly shows the difference for billing purposes (thus cost recovery purposes) related to these customers billed energy profiles when they move from a full requirements customer to a partial

[11] As of June 30, 2016, TEP had added over 9,000 DG customers since December 31, 2011 (an approximate 300% increase when compared to count in the test year used in the last cast).

requirements customer. The second chart clearly shows the degraded load factor for these customers. They are billed for very little energy in comparison to the load they draw from the system. It is simply smoke and mirrors to assert that DG customers act like full requirements customers in their usage of the system when applying rates that recover cost to serve through volumetric energy charges.





Q. Please address the assertion that it's discriminatory to treat DG customers differently than standard full requirement customers.

A. This position, quite frankly, is wholly unfounded. There is more than ample justification to put DG customers on a separate rate structure. TEP witness Dr. Overcast, provides detailed Rebuttal Testimony as to (i) what the cost to serve DG customers is, (ii) why separate rate treatment is appropriate for DG customers, (iii) why the current rate structure is not capable of reflecting costs for DG customers (as partial requirements customers) and (iv) why a separate rate class for DG customers must include demand charges. In short, and especially given the fact that allocating costs on a two-part rate design for DG customers does not provide the right price signals or properly reflect cost recovery or causation, DG customers should be placed on a separate three-part rate with demand charges. TEP strongly disagrees with any assertion that it is discriminatory to

recover the cost of serving a partial requirements customer (DG customer) based on how they use the system.

> When the difference in the annual bill of a full requirements customer and a partial requirements customer with identical peak demands is 19 times a partial requirements customer's total bill the subsidy is no longer just and reasonable and constitutes undue discrimination. The only practical solution is to eliminate the net metering provision and recover costs under a separate rate schedule for partial requirements customers as proposed by TEP.[12]

Q. Have other public utility commissions found justification to place DG customers in a separate rate class?

A. Yes. The commission in Nevada and Utah, for example, placed DG customers (NEM customers) in a separate rate class. The Utah Public Service Commission, in Docket No. 14-035-114, found reason to order, on November 10, 2015, cost of service studies that segregates DG customers from the class they would otherwise participate in and as part of the Utah PSC's examination of the costs and benefits of net metering. Clearly, utility commissions in other states are finding that DG customers impact the grid differently than traditional full requirements customers.

IV. NET METERING TARIFF.

Q. Briefly summarize the Company's proposed net metering tariff

A. Under TEP's proposed Net Metering Tariff, new DG Customers, among other things, (i) would not be allowed to "bank" or carry-forward excess kilowatt-hours ("kWh") to offset future electricity consumption and (ii) would be compensated for excess energy at the Renewable Credit Rate.[13]

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[12] Overcast Rebuttal, page 76:15.

[13] Equivalent to the most recent utility-scale renewable purchased power agreement connected to the distribution system of Tucson Electric Power.

Q. Is the Company willing to consider other net metering proposals or alternative methodologies of valuing excess generation produced by DG customers?

A. Certainly. However, with the exception of RUCO, none of the other parties in this proceeding provided any new net metering proposals or any real alternatives in their testimony.

Q. Is the current rate case proceeding the proper venue to approve a new net metering tariff?

A. Yes, without question. I would like to point out that TEP and its sister company, UNS Electric ("UNSE"), filed applications in March 2015 to update their net metering tariffs.[14] Although both TEP and UNSE believe that the Commission can approve a net metering tariff outside of a rate case, several parties who are Intervenors in this rate case, argued that a net metering tariff must be approved in a rate case. In light of the procedural posture in that docket, in June 2015, TEP withdrew its net metering application and accelerated the filing of its rate case. Yet these parties have yet to offer any new net metering proposals in this docket.

While we understand Staff's desire to wait for the outcome of the Commission's investigation of the value and cost of DG (Docket No. E-00000J-14-0023), this proceeding is the proper venue for approval of a new net metering tariff for TEP. It is unclear when that proceeding will conclude and what result it will ultimately produce. On the other hand, this rate proceeding will provide sufficient Company specific data and evidence to support the Commission's approval, modification or rejection of TEP's proposed net metering tariff.

[14] March 25, 2015, Docket No. E-04204A-15-0099 (TEP) and Docket No. E-01933A-15-0100 (TEP).

Q. Do you have any estimates of how the Company's proposed three-part rate structure and net metering tariff will impact new DG customers?

Yes. Company Rebuttal witness Mr. Bachmeier is addressing these impacts in his Rebuttal Testimony.

V. ECONOMIC DEVELOPMENT RATE.

Q. Briefly describe the Company's proposed Economic Development Rate ("EDR").

A. As a way to help promote economic development in the Company's service territories, TEP proposed to offer discounted rates to new or existing large business customers that meet certain requirements, including a minimum load factor.

Q. Would you like to make any clarifying remarks about the Company's proposed EDR?

A. Yes. The testimonies of several parties express concerns about costs being shifted from EDR customers to other customer classes. I would like to emphasize that the any lost non-fuel revenues resulting from discounts provided to customers through the EDR *will be borne by the Company*. TEP will not seek recovery of any lost non-fuel revenues associated with the EDR in future rate case proceedings. The long-term benefits of attracting or retaining large, high load factor customers greatly outweigh the short-term costs.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

Rebuttal Testimony of

H. Edwin Overcast

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-1933A-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

REBUTTAL TESTIMONY OF H. EDWIN OVERCAST

ON BEHALF OF

OF TUCSON ELECTRIC POWER COMPANY

JULY 25, 2016

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I. Introduction.

Q. Please state your name and business address.

A. H. Edwin Overcast. My business address is P. O. Box 2946, McDonough, Georgia 30253.

Q. By whom and in what capacity are you employed?

A. I am a Director, Black & Veatch Management Consulting, LLC.

Q. Please describe your educational background and business experience.

A. A detailed summary of my educational and professional experience is provided in Appendix A to this testimony. I have a B. A. degree in economics from King College and a Ph.D. degree in economics from Virginia Polytechnic Institute and State University. My fields of study include microeconomic theory, industrial organization and public finance. I have been employed in the energy industry for more than 40 years in various rate, regulatory and planning positions. My industry employers included the Tennessee Valley Authority, Northeast Utilities (an electric and gas holding company) and AGL Resources (a gas holding company). I have been employed as a utility consultant since 1998 providing rate, regulatory, strategic and other consulting services to utility clients. In my various positions, I have testified before state and federal regulatory bodies, Canadian provincial regulatory bodies, state and federal legislative bodies and in various courts. I have previously testified before the Federal Energy Regulatory Commission ("FERC") on a number of electric, gas pipeline and oil pipeline issues.

Q. On whose behalf are you submitting this testimony?

A. I am testifying on behalf of Tucson Electric Power Company (TEP or the Company).

Q. Have you previously testified before the Arizona Corporation Commission (ACC or the Commission)?

A. Yes. I have testified in the UNS Electric Inc. rate case and in the Commission's Investigation of Value and Cost of Distributed Generation.

Q. Please provide a list of state and Canadian jurisdictions in which you have testified.

A. In addition to Arizona, I have testified in Connecticut, Massachusetts, Georgia, Tennessee, Montana, Missouri, New York, Ohio, Michigan, Arkansas, New Jersey, Oklahoma, Kansas and Maryland. In Canada, I have testified before the Ontario Energy Board, the Alberta Energy and Utilities Board, the New Brunswick Energy and Utilities Board and the British Columbia Utilities Commission. My testimony has been related to issues such as cost of service, rate design, prudence, rate of return, regulatory risk, performance based regulation, competition and unbundling.

Q. During your career have you made presentations to energy related training and other programs?

A. Yes. I have been an instructor for the Edison Electric Institute's Rate Fundamentals and Advanced Rate School related to cost of service. I have been an instructor in both the American Gas Association's Rate Fundamentals and Advanced Rate courses. I have been an instructor for the Southern Gas Association's Intermediate Rate Course and for the RMEL I have provided training related to regulation. I have made numerous presentations to trade association meetings including the EEI Rate Committee, the AGA Rate Committee, the AEIC Load Research Committee, SURFA and other industry sponsored programs. I have made presentations to NARUC events and events sponsored by academic institutions. I have also written broadly on various subjects related to utility regulation,

including issues related to the integration of distributed generation into a utility system and the design of rates for the 21st century.

Q. Have you provided expert testimony on cost of service and rate design related to net metering, rates for distributed generation (DG) customers and development of rates for purchase of energy from dg customers?

A. Yes. My testimony in Maryland and Arizona addressed these issues and more related to cost of service, rate design, net metering impacts and the impact of purchasing excess generation at the full retail rate. In that testimony, I developed specific measures of the level of subsidy created by net metering and demonstrated that the Commission's net metering rule resulted in undue discrimination based on the factual circumstances for the utilities.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. My rebuttal testimony addresses a number of areas related to the economics of DG from the perspective of the utility, its customers and economic efficiency. Specifically, I respond to issues raised by the Commission Staff, Vote Solar (VS), the Energy Freedom Coalition of America (EFCA), Residential Utility Consumer Office (RUCO), Southwest Energy Efficiency Project (SWEEP) and Western Resource Advocates (WRA), Arizona Community Action Association (ACAA), Mr. Kevin Koch and the Solon Corporation (Solon). I address the following issues as discussed by some or all of these parties:

- The cost basis for a customer charge and numerous fallacies associated with opposition to the charge and its calculation;
- The reason partial requirements customers and full requirements customers have different costs;

- The subsidies being provided to DG customers under the current rate design and net metering tariff with banking;
- The cost to serve solar DG customers based on three different cost studies: the base study that merely separates solar DG customers from the residential class, the counterfactual study that measures the cost to serve the solar DG customers as if the customer never adopted solar DG and the solar class study that allocates cost to these customers based on their own unique load characteristics;
- The nature of the undue discrimination among customers with the same cost of service;
- The economic and regulatory rationale for a separate rate for a DG customer that requires different treatment than a standard customer until such time as utility rates are fully unbundled and customers are classed based on the cost causing characteristics of their service;
- The economic and regulatory basis for multi-part rates including customer charges, demand charges and time differentiated energy charges;
- The efficacy and efficiency of demand based rates for all customer classes and how such rates will impact customers;
- The ability of customers to respond to more complex price signals,
- The role of fairness, efficiency and gradualism in developing and implementing new mandatory rate designs; mitigation of adverse impacts during the rate design transition;
- The reason all customers should be on the same rates with any special considerations (Lifeline customers for example) should have considerations outside of the rate structure per se;
- The customers who choose to use the utility system in ways that result in high unit costs (low load factor customers or large on-peak users for example) should pay the

full costs imposed on the system under the cost causation principle and the matching principle of rates; and

- The importance of multi-step transition plans to assure timely and efficient implementation of the best rate design for all customer classes in an expeditious manner.

Finally, I recommend transition steps necessary to rates that match costs and revenues and to minimize the impact of changes over time. I also note that the Commission has a duty to eliminate the undue discrimination that exists in the current rates as it relates to the comparable service between solar DG customers and full requirements customers. Although these issues as they relate to net metering, three part rates and the inefficiency and intraclass subsidy from inverted block rates are all closely intertwined as is evident in the various sections, I have discussed the topics in separate sections to identify the focus on a particular issue.

Q. How is your rebuttal testimony organized?

A. My testimony is organized in sections beginning with this introduction that includes a summary of my recommendations and the individual sections as follows:

II. Customer Cost Analysis and Customer Charges

III. Economics of Serving Full and Partial Requirements Service Customers

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VII. The Concepts of Fairness, Efficiency and Gradualism

VIII. Customer Response to More Complex Price Signals

IX. Miscellaneous Issues

X. Conclusions

Q. Please briefly summarize your conclusions and recommendations.

A. Based on my testimony I conclude the following:

1. The minimum system for classifying distribution costs in accounts 364-368 as proposed by TEP is a necessary condition for reflecting cost causation on the TEP system. That conclusion is supported by rigorous econometric analysis, public utility accounting, the NARUC Manual, numerous academic and industry literature written by scholars and rate practitioners over more than 100 years and analysis of TEP's own data. The only option offered to the minimum system does not result in an allocation of costs that reflects the real physical assets that underlie service to customers and thereby fails the test of cost causation. The Commission should affirm the use of the minimum system classification in the TEP cost study going forward.
2. Increasing customer charges as proposed by TEP is solidly grounded in cost causation, economic efficiency and results in rates that are just and reasonable and not unduly discriminatory. The Commission should approve the TEP customer charges as filed even if they do not grant the full revenue requirement increase.
3. The rates resulting from net metering with banking are decidedly not just and reasonable and rise to the level of undue discrimination. The Commission has an obligation to cure undue discrimination and should adopt the TEP proposal for modifying net metering by placing customers on a separate rate schedule designed specifically for partial requirements customers including solar DG customers. The rate should be based on the treatment of solar DG customers as a separate class of customers in the TEP cost study.
4. The elimination of the top two tiers of the TEP residential rate is a necessary step to begin the transition to more cost-based and efficient rate designs that comply with the

just and reasonable standard for rates. Just and reasonable rates ultimately require a multi-part rate with customer, demand and energy charges.

5. The Lifeline rates should be consolidated as part of a plan to serve all full requirements residential customers under a single rate with customer, demand and TOU energy charges.
6. Customers can and will respond to the more efficient rates and that response will vary broadly among customers based on their own choices designed to optimize their individual satisfaction and valuation of electric service.
7. No TEP proposals constitute retroactive ratemaking.
8. The three cost studies filed in my testimony provide a clear picture of the cost of service benefits DG customers receive and show that despite those benefits, the treatment of DG customers on the current two part rate result in significant negative earned returns for DG customers

II. <u>Customer Cost Analysis and Customer Charges.</u>

Q. Please summarize the positions of the parties that you will be responding to in this section.

A. Many of the parties filing testimony related to cost of service and rate design oppose the development and implementation of a higher customer charge based on a variety of arguments. These arguments range from using a customer cost estimate that only reflects a portion of actual customer costs to misapplied policy arguments and also in a number of cases represent a classic example of rent-seeking as noted by Alfred Kahn in his monograph "Letting Go: Deregulating the Process of Deregulation" published by The Institute of Public Utilities and Network Industries at Michigan State University in 1998. Rent-seeking is defined as "the activity of a person or firm that tries to obtain benefits for

themselves through the political arena"- the Commission in this case. Typically the benefit consists of a subsidy for their product or service including favorable tax treatment and measures that inhibit competitors such as inefficient regulated rates. The subsidy supporting parties distort facts, rely on fallacious arguments, make economically inefficient arguments and misuse data and analysis all of which lead to higher subsidies for solar DG and conservation.

The benefit sought by the subsidy proponents in this case is energy charges for residential rates that exceed marginal cost by an even greater amount than current rates and continue to overcharge high load factor customers whose energy consumption is billed in the highest tiers of the current rates. This is contrary to both economic efficiency and cost based rates and results in rates that are unduly discriminatory by allowing solar DG customers pay far less than comparable full requirements customers for the same service.

Q. How should regulators respond to this type of rent seeking activity?

A. It is not the purpose of regulation to create an economic environment that results in inefficient competitors who have higher costs than both the utility and more efficient competitors having special preferences and protections that result from subsidies and from restraining efficient responses from the utility. The proposals made by DG advocates, and in particular rooftop solar DG, in response to more efficient and equitable rates proposed by TEP represent the worst type of rent-seeking whereby they seek to perpetuate their profitability at the expense of captive consumers and low income customers. Dr. Kahn described this mixed monopoly and competition model as it relates to the local distribution network for electric utilities and noted the following with respect to the role of regulation:

> It is clearly not possible to totally eliminate direct regulation of what we have traditionally considered to be the authentic public utilities. The reason, of course, has been the persistence of monopoly, particularly in the local distribution

networks and also in electric transmission, which has required continuing regulation for two closely related reasons:

- To protect captive, principally residential and small business, customers;
- To ensure fair and efficient competition between the integrated utility companies and the challengers dependent upon their access to their monopolized or partially-monopolized facilities, including safe guarding against cross-subsidization of that competition by the incumbent utilities at the expense of their monopoly customers.[1]

These two reasons represent the fundamental obligation of regulation in the mixed monopoly and competition model. The monopoly aspects of the public utility, in particular the facilities associated with service delivery, must be the focus of the evaluation of evidence in a rate case. There is no question that the issue of customer cost and the appropriate customer charge become a first step in setting rates that protect captive customers from subsidizing the purveyors of rooftop solar DG. However, the customer charge is not solely a mechanism related to a DG subsidy, it is also a cost based, unbundles charge that is needed for all customers to reflect the principles of cost causation and matching principles of rates. The magnitude of this subsidy is quite large as I will demonstrate based on cost of service studies and by illustrating the undue discrimination resulting from net metering and banking. The subsidy is also far greater than the avoided cost that PURPA and FERC regulations implementing Section 210 of PURPA set as a cap on payments for energy from QFs. The first step for regulation is needed to protect the captive residential customers who cannot (or choose not to) avail themselves of DG or net metering, recognizing that the vast majority of residential customers are not DG customers, and that at least a plurality and more than likely a majority of the residential class will never be DG customers. Second, Dr. Kahn notes that competition should be fair and

[1] "Letting Go: Deregulating the Process of Deregulation", Alfred E. Kahn, 1998, MSU Public Utility Papers, p. 17.

efficient. As I will explain later in this testimony the implications of net metering are such that the competition for the end use loads served by DG is neither fair nor efficient under the net metering, banking and volumetric rates commonly used for residential service. Third, and more importantly, I will show that net metering creates cross-subsidization, not by the incumbent utility, but by the rent-seeking behavior of the solar DG advocates that occurs at the expense of customers who remain monopoly customers. This cross subsidization rises to the level of undue discrimination for solar DG customers that is required to be cured.

Typically, the argument for this rent seeking behavior is that it will have a small dollar impact on customers providing the subsidy. This argument can be found in the testimony of Vote Solar[2], Solon[3] and EFCA[4]. Others argue for low fixed costs based on social policy issues that include low income impacts, conservation impacts, and inequities among customers in the residential class. None of these arguments is well founded when viewed in the light of economic theory, sound social policy and cost causation in spite of claims to the contrary.

Q. What are the essential elements for the regulated delivery component to avoid creating cross-subsidy from the monopoly component of the market to solar DG customers who have chosen competitive alternatives?

A. Under regulation, artificial subsidies may be sustained for a period of time but must be addressed ultimately if utility service is to be sustainable. Waiting to address these subsidies when the solar DG market is much larger is far more disruptive to public policy and private investments at that time then it is to address this issue now when only a fraction of existing customers are impacted. Where certain projects or services are

[2] Direct Testimony and Exhibits of Briana Kobor on Behalf of Vote Solar, See sections 4, 5 and 7.
[3] Direct Testimony of Brian A. Seibel for Solon Corporation, p. 66-70
[4] Direct Testimony of Mark E. Garrett, EFCA, p. 33-42 and in particular the recommendation to maintain the status quo level at line 7, p. 42

subsidized through regulation, the result is that there is excess and inefficient investment in the favored services such as rooftop solar DG in this case. The result will not be consistent with least cost planning or even efficient operation of the utility. Ultimately, regulated rates must ensure that the monopoly segment of the market must establish fully unbundled rates so that when a customer uses a monopoly service the customer pays for the costs that the customers' use imposes on the monopoly. To establish unbundled rates the cost of service must be unbundled for the services provided. Rates must be developed that signal the factors that cause cost by customer groups that have homogeneous characteristics that cause the cost and match those costs in rates in the prospective period. When rates reflect class cost of service on an unbundled basis and the underlying cost of service reflects the principles of cost causation and matching, subsidies will be eliminated; the price signal in the rates will incent efficient use of resources as required under the purposes of PURPA for net metering; rates will be just and reasonable; rates will not be unduly discriminatory; and investment in DG will be consistent with least cost planning and efficient competitors will earn the required market return for the associated risk they take. In summary the following elements must exist for long term stability and sustainability of the mixed market model:

1. Cost of service reflects cost causation for each class of customer and each service provided including access, capacity and kWhs.
2. Rates match cost in the rate effective period.
3. Rates are fully unbundled such that all energy related costs are recovered in energy charges (preferably seasonal and time differentiated based on marginal cost differences), fixed capacity costs are recovered in demand charges and access costs in customer charges that may not be the same for all customers in a class when the services they select differ.
4. Price signals should reflect marginal cost to the extent practical while still matching costs and revenues.

5. Costs not included in test year revenue requirements such as the present value of future avoided costs or the levelized cost of future avoided energy should not be part of rates or part of valuation of assets that have no long-term, enforceable, contractual obligation for service and even with a long-term power purchase contract energy should be valued at the market as the market changes through time to protect the interests of customers in reasonable rates.

6. There is no reason to believe that investment in rooftop solar DG is entitled to a fixed energy price over the life of the asset since other behind the meter investments by customers such as EE or other DER investments and even competitive merchant power plants are not afforded fixed prices that guarantee the economics of an investment. Further, such a guarantee is not even permitted for as available resources under the FERC regulations applicable to power purchases from QFs.

A. Minimum System to Define the Customer Charge

Q. Does a group of witnesses raise issues related to the allocation of customer costs?

A. Yes. A number of witnesses recommend the concept of the basic customer method for allocating customer costs in the cost study and determining the customer charge[5]. There are two issues with the basic customer method that must be addressed separately. The first is the use of this method in cost allocation and the second is whether this method is valid for determining the customer charge. I will discuss both these issues.

Q. Is it reasonable to use the basic customer charge and NCP allocation of all other distribution in the cost study?

[5] The list includes Kobor of Vote Solar, Huber of RUCO, Garrett of EFCA,

A. No. To begin, the classification is inconsistent with public utility accounting theory, the cost allocation process as developed by NARUC, cost causation, empirical analysis and the economics of efficient rates for a utility that is a declining cost firm. I discuss each of the points below.

Q. Please explain the inconsistency with utility cost accounting and NARUC cost allocation.

A. In classifying all of the distribution plant in Accounts 364 through 368 to demand and allocating those plant costs on non-coincident peak (NCP), these positions do not fairly allocate plant to customer classes for a variety of reasons. As Dr. James Suelflow writes in his treatise Public Utility Accounting: Theory and Practice published by the Institute of Public Utilities at Michigan State University: "... distribution transformers and primary and secondary lines including conductors and devices (account 365 "Distribution Plant") and poles and towers (account 364 "Distribution"), all contain capacity and customer costs."[6] Dr. Suelflow recognizes that costs are more closely related to customers the closer one approaches the ultimate customer.

In other words, assets that are in closer proximity to the load served reflect less diversity and the classification of the costs associated with those assets should recognize this point. The recommendations advanced by these advocates of the basic customer method fail to recognize that class NCP is more appropriately used in 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.

Diversity can be seen by the fact that distribution substation transformer capacity is more than transmission transformer capacity measured in MVA. Typically, distribution transformer capacity is greater than substation capacity and that excludes all customer

[6] Public Utility Accounting: Theory and Practice, James E. Suelflow, The Institute of Public Utilities at Michigan State University, 1974, p.241

owned transformers that would increase the difference. These statistics further indicate the way diversity impacts loads as you move closer to customers. For that reason alone, those parties that support the basic customer method and class NCP demand allocation of accounts 364-368 are misguided because that allocation cannot be used as it does not reflect cost causation and cannot be relied upon as a basis for revenue allocation or for rate design.

Public utility regulatory accounting, including the NARUC Electric Utility Cost Allocation Manual ("NARUC Manual") supports the classification of distribution plant between customer and demand. In fact, the NARUC Manual does not even mention the basic customer method as an alternative for classifying and allocating distribution plant.

There is no question that the NARUC Manual states that the distribution plant costs in Accounts 364-368 have both a demand and a customer component. The NARUC Manual states "When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, *the utility must classify distribution plant data separately into demand- and customer- related costs.*"[7] (Emphasis added.)

This is not a new concept. In 1963 Constantine Bary published his treatise Operational Economics of Electrical Utilities. This rigorous study of utility costs and how loads cause those costs provides a summary chart of cost causation that is attached as Exhibit HEO- 1. This exhibit shows that a portion of the distribution plant beginning with primary lines is customer related. In the parlance of uniform system of accounts this is accounts 364-368. I should note that support for both the minimum system concept and for customer charges to reflect these costs is not new or novel. Writing in 1900 Henry L. Doherty formulated a three part rate consisting of a customer charge, demand charge and energy charge.[8] In the

[7] Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners, February 1991, p.95

[8] See for example Bonbright 1988 Edition p. 401 for reference to Dohery.

original paper "Equitable, Uniform and Competitive Rates" Doherty defined the minimum costs associated with "readiness to serve" and specifically included not only the components of the basic customer costs but the costs of poles, lines and conductors with 50% classified to the customer component and 50% to the demand component. His analysis also included overhead loaders in the cost per customer.[9] Writing in 1956, Russel Caywood describes customer costs as "Varies with the number of customers served and includes investment charges and expenses relative to a *portion of the general distribution system,* service drop or other local connection facilities, metering equipment, meter reading, billing and accounting."[10] Further, H. E. Eisenmenger has written an extensive analysis of electric utility costs in 1919 and includes in the customer cost component the minimum size of poles and conductors. He states "Up to a certain size of consumer this investment will be practically constant per consumer and above that size we can regard it as composed of two parts: A constant part (cost of average length of service connection, if constructed with minimum size of poles and minimum thickness of service wires: also cost of minimum size of meter, etc.) and another part proportional to the maximum demand of the consumer."[11]

The above citations demonstrate a number of conclusions. First, the minimum system concept for calculating customer costs is neither new nor novel. Despite the protests of the parties opposing the use of the minimum system concept, its pedigree has been established for over 100 years by a variety of disciplines and industry participants including engineers, entrepreneur utility owners, rate experts and others. For example, Henry L. Doherty, was the founder and owner of Cities Service Company (later CITGO), which served as a

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[9] A reprint of the 1900 article may be found in The Development of Scientific Rates for Electricity Supply, Printed for Private Circulation Only by The Edison Illuminating Company of Detroit, 1915, pp.53-78 (Available from GOOGLE Books)

[10] Electric Utility Rate Economics, Russell E. Caywood, Sixth Printing, 1972, Sponsored and Distributed by Electrical World and Russell E, Caywood, p. 26

[11] "Central-Station Rates in Theory and Practice, Seventh Article—The Consumer Cost, What It Includes and How It Varies—Determining the Numerical Values of the Three Elements of Cost—Analytical Valuation of Costs", Electrical Review, Volume 75, No. 8, 1919, p. 304 (Available from GOOGLE Books)

holding company for the utility firms in all three energy sources available at the time—petroleum, natural gas, and electricity. The arguments related to the basic customer method for reflecting cost causation are flawed when considering the depth of study and analysis that supported these early industry pioneers in determining the customer cost component. Essentially the basic customer method is devoid of the kind of reasoned analysis and strong empirical support that exists for developing customer costs using the minimum system.

Q. Is there empirical analysis to support the use of the minimum system?

A. By using class NCP as opposed to classifying these distribution accounts as customer and capacity, the parties incorrectly allocate more costs to larger customers who may not even use any of the facilities allocated to them. A simple example will illustrate this point. Consider a company with one industrial customer who has a 2500 kVa transformer installed. A typical installed cost for this transformer would be about $40,000. Also assume that the system served the same 2500 kVa of residential load using 50 50 kVa underground transformers that serve 400 residential customers. Those transformers typically cost about $4200 per transformer installed or about $210,000. Allocation of these costs on NCP would allocate the industrial customer $125,000[12] of rate base and the same amount to residential customers. Thus the advocates of the basic customer method would allocate less plant to residential customers than they actually use and at a lower cost than those actually caused by residential customers. The minimum system method would classify 70% of transformer cost on customers and the remainder would be allocated on capacity. That allocation results in about $193,000 of transformer costs to the residential class. Thus the minimum system method allocates cost more closely to causation and shares some of the scale economies between the customer classes. This same principle

[12] Based on 50% of the sum of the classes NCP

applies for conductor and for poles in the case that overhead transformers are used. Thus the basic customer method is actually more results oriented than based on the principle that those customers who cause the costs should be responsible for the costs.

Q. So the reality of economies of scale points against using the basic customer method?

A. Correct. The fundamental point is that there are substantial economies of scale for all sizes of transformers, overhead and underground conductor and poles. In each case the per kVa cost of industrial transformers is below the cost for every size of residential transformer except for the largest and least used size of residential transformer. Some industrial transformers are even lower cost per kVa than the lowest cost single phase transformers used for residential customers. Using a demand allocation factor alone implicitly makes the incorrect assumption that the cost of transformer capacity is the same for all classes. It is not. This is the type of empirical analysis that is necessary to develop an appropriate determination of the best available method for allocating costs between classes. By classifying plant between customer and demand, the residential class receives a higher weighting of transformer costs consistent with cost causation since the unit costs per kVa for residential transformers is higher and they use many more transformers than other classes of customers. The basic customer charge method cannot recognize this reality. Bonbright recognizes this phenomenon and states that the exclusion of minimum system costs from demand stands on "much firmer ground."[13] This is exactly where the basic customer method places those costs.

By allocating the cost of transformers on NCP only, the parties supporting the basic customer method unfairly and incorrectly allocate all of the economies of scale in transformer costs to the residential class and compounds that error by allocating fewer transformers to the class than residential customers actually use. Any witness advocating

[13] Principles of Public Utility Rates, James C. Bonbright, 1961. p. 348

the use of the Basic Customer Method would produce a result that is inconsistent with cost causation as demonstrated above. Essentially, the basic customer method is not a method for calculating the customer component of costs that is based on the gold standard of cost causation because it fails to reflect any costs more than meter, service and direct customer accounting costs such as meter reading and billing in the customer costs. As often applied, it does not even include the full payroll related costs associated with the employees who provide the basic service and it does not include the office space used by these employees. These two flaws are enough to illustrate the arbitrary and incomplete nature of the development of the concept.

The basic customer method relies on an empirically incorrect assumption. Similar economies of scale occur for other distribution accounts with the result that allocation without the minimum system significantly under allocates costs to the residential class and over allocates costs to larger demand customers who use far less of the distribution assets than residential customers. Since scale economies apply across all components of the minimum system including conductor and poles, the same conclusion applies to the other distribution accounts. For conductor, larger customers are typically located closer to substations than residential customers and therefore require fewer miles of conductor. The NCP allocator over allocates distribution lines significantly to larger customers and that does not take into account the lower unit cost per kVa of line capacity to serve these customers. Namely, absent the use of the minimum system the costs for smaller customers is under allocated and is over allocated for larger load customers.

Q. Is it fair to conclude that the advocates of the basic customer charge support the resulting higher energy charges in rates?

A. Yes. As the cost study filed by the Company illustrates, there are no energy-related costs for any component of the transmission or distribution costs and virtually none for

production plant. Despite this fact, the parties who oppose demand charges have assumed that all of the fixed production, transmission and distribution costs should be allocated to the energy component of the rate and would have higher energy charges for all customers. The testimony of these advocates uniformly point to the resulting higher energy charges as a useful feature of lower customer cost allocation and thus lower customer charges.

Q. Does using the basic customer method in these circumstances violate the matching principle?

A. Yes. By collecting costs that are demand related in energy charges the rates that result violate the matching principle, which provides that the rates charged should match the costs for all customers. Recovery of fixed costs in the energy component of the rate cannot match cost causation for demand unless all customers in a class have identical or near identical load factors. (This is the point noted by Caywood above.) That is not the case, particularly for solar DG customers.

Failure to follow the minimum system classification and in addition putting these costs in the energy charge would unfairly cause customers who use more kWh to pay more for the same customer services provided to customers who consume less, and for customers with the same delivery services to pay more than identical customers with lower load factors.

Q. Is there a particular issue with using the basic customer method for solar DG customers?

A. Yes. In the case of net metering, solar DG customers are not paying the actual cost of the facilities they use related to the distribution system as the cost of service studies discussed below proves. I should also note that it is not necessary to provide a separate class cost study for solar DG customers to reach this conclusion. It is as simple as the cost of service study allocates the minimum system costs and the class NCP costs and production demand

costs properly to the residential class including the load shape of solar DG customers. In my view, this allocation is conservative because of the different load characteristics of DG solar customers. The problem is not that the cost of service study needs to be changed; it is the rate design that recovers the allocated fixed cost, both customer and demand, on energy. Since over half of the solar DG bills are for zero kWh, and nearly all of the bills do not exceed the first block, the company collects far less than the average class costs for those customers. It is impossible that solar DG produces revenue enough to cover their allocated costs with so few billed kWh.

Q. Some advocates of the basic customer charge method rely on Bonbright to support their method. Please comment.

A. I have discussed above that the accepted method for classifying these costs is to classify them as both demand and customer. Parties opposing various aspects of cost allocation use Bonbright to support the basic customer method. In fact, Bonbright states his position regarding customer costs as "operating and capital costs found to vary with the number of customers, regardless, or almost regardless, of power consumption."[14] I also note that Bonbright states that the minimum system costs should not be allocated to the customer component. Bonbright also continues on to say that the exclusion of minimum system costs from demand stands on "much firmer ground."[15] The key point is that customer costs vary with the number of customers. As I have shown above transformer and other distribution costs vary with the number of customers. Further the relationship between customers and cost is an empirical relationship that has been analyzed in depth by economists in regulatory proceedings in many cases and around the world.

[14] Principles of Public Utility Rates, James C. Bonbright, 1961. p. 347
[15] P.348

Q. Please summarize the research showing that distribution costs vary with number of customers.

A. The correlation between customers and distribution costs has been confirmed by academic and regulatory research work related to estimating Total Factor Productivity (TFP) for use in price cap regulation. Under this system, where customers or connections has been an output measure for calculating the X-Factor in the formula P = I – X. The formula P= I – X is essentially a formula that relates either price or the functional equivalent revenue requirements to inflation and changes in productivity as measures by the relationship of physical outputs like customers and demand to measures of physical inputs such as meters or transformers. For example, the following statement from an Australian electric distribution TFP study says "The connection component recognises that some distribution outputs are related to the very existence of customers rather than either throughput or system line capacity. This will include customer service functions such as call centres and, more importantly, *connection related capacity (eg having more residential customers requires more small transformers and poles)*." (Emphasis added.) This information is developed specifically for a network electric utility providing delivery services. I would note that the emphasis on connections is the result of the correlation of distribution costs to the number of customers. In a more recent study related to the electric distribution utilities in Ontario, Canada, The Pacific Economics Group (PEG) found that customer number was an empirically significant output measure for determining productivity. In each case the productivity measure is used to determine the expected changes in costs over time. As an aside, the customer component of TFP has the largest cost elasticity weight meaning the customer component is more significant than the other output measures. In addition to Australia and Ontario, other jurisdictions such as Great Britain and the Netherlands also use customer numbers to develop TFP.

Based on this research, it is fair to conclude that the weight of modern empirical evidence is fully supportive of the minimum system use to classify distribution system costs in accounts 364-368 as both customer and demand. I conclude that this empirical evidence, not available in 1961 or even in 1988, would have Bonbright supporting the minimum system because it aligns with his principle definition noted above. The goal in this case, as dictated by not only regulation but affirmed by the courts, is to allocate costs based on the principle of cost causation.

Q. Are there other authorities that support the use of the minimum system and demand charges?

A. Yes. Alfred Kahn clearly defines that the parameter of the defect in cost of service is where marginal costs diverge from average costs. That divergence occurs for any utility exhibiting economies of scale. Kahn also states that the full distribution of costs "is in part along the lines that reflect true causal responsibility."[16] He goes further in that same chapter to conclude that "for those segments of demand that do not have the requisite high elasticity—prices based on fully distributed costs have much to recommend them."[17] Kahn concludes by noting "the respective average historic cost responsibilities of the various classes of service plus proportionate contributions to overhead will most likely strike the various rate-payers as equitable and non-discriminatory."[18] There is nothing in Kahn's view that is in any way inconsistent with the Company's cost study. Kahn's views however are inconsistent with the those parties who advocate the basic customer method and inclusion of all costs in energy charges since they do not reflect cost causation as demonstrated by both theory and pragmatic analytics. Further, the potential for loss in social welfare related to efficiency costs as a result of low customer charge and higher

[16] The Economics of Regulation: Principles and Institutions, Alfred E. Kahn, John Wiley and Sons, Inc., New York, Sixth Printing, 1995, p. 150
[17] P. 158
[18] P. 158

kWh charges is quite large particularly when the targeted benefits of Lifeline rates are considered as part of the income redistribution impact. Simply, the parties' proposals to limit the customer charge represent a level of economic inefficiency that will be quite large to the detriment of the customers and economy in the TEP service territory.

Q. What do you conclude about the use of the minimum system to classify cost between customer and demand?

A. Based on the above evidence, the minimum system classification reflects cost causation and is supported by regulatory accounting, the NARUC cost allocation manual, empirical evidence that is utility specific and empirical analysis that is applied to a wide array of utilities. The evidence shows that the basic customer method is not cost based, and it therefore must be rejected.

B. The Appropriate Customer Charge

Q. Is the TEP customer charge proposal a reasonable value for the customer charge?

A. Yes. I reach this conclusion based on the discussion below that represents both practical and theoretical considerations.

Q. Please describe the theoretical issues for determining the customer charge.

A. Economists have discussed the theory of price determination under conditions of decreasing costs in detail. The seminal work in the field is an article entitled "The Marginal Cost Controversy" by Ronald Coase[19]. The Coase argument supports multi-part pricing[20] consisting of a variable charge set at marginal cost and fixed charges to recover the total

[19] "The Marginal Cost Controversy", R. H. Coase, Economica, New Series, Vol. 13, No. 51. (Aug., 1946), pp. 169-182.
[20] Ibid. p. 173

cost of service including what is characterized as customer costs and the remainder of past or sunk costs of the system would be included in the customer charge for a two part rate and in the customer and demand components of a multi-part rate. Since this is wholly consistent with the TEP position on the development of the charge, the proposal is theoretically sound. The proponents of the status quo fail to recognize that the current rates are definitely inefficient based on economic theory since there is no rationale for multiple levels of marginal prices that recover far more than marginal cost.

Q. Are there practical reasons for supporting the TEP proposed customer charges?

A. Yes. Increasing the customer charge is critical for rates to be just and reasonable. Just and reasonable rates must reflect cost causation. Since the customer component of cost is the same for all customers in a properly designed rate class, setting the rate below the properly determined customer costs (discussed above including the minimum system classification) means that low use customers are subsidized by high use customers. This creates an inequity that is not justified except for social policy related to certain customers who have incomes that allow them to qualify as recipients of low income, poverty related services. Maintaining low customer charges based on the impact on low use customers assumes incorrectly that there is a correlation between low use and low income customers who qualify as low income customers with poverty status. The low use/poverty argument suffers from a number of defects that have been discussed in academic studies (little or no correlation between low usage and poverty levels) and as well as in rate cases. Importantly, there is no reason to limit the customer charge for <u>all</u> customers for the benefit of eligible low income customers when they represent only 4.23% of bills under 500 kWhs. Further, eligible low income, low use customers (less than 500 kWhs) actually represent less than 44% of all low income bills. This is statistically the same percentage as the non-low income customers under 500 kWhs. Further, there are almost as many bills less than 500

kWhs for solar DG customers (74,000) as there are for low income customers (78,000) with solar DG having only about two-thirds the number of customers. The policy implication of the argument to limit customer charges to protect low income customers is grossly inefficient and should be rejected. In fact, there is no rationale for having Lifeline customers served on a different rate schedule than all other customers. The existing Lifeline customers should have the choice of the residential default rate or the optional rates so that they face the same price signals as all other customers. Qualifying, low income customers should receive bill assistance that is targeted to each customer's circumstance.

Q. What about the argument made by witness Zwick that only a small percentage of low income households are enrolled in Lifeline?

A. This is a common argument made by low income advocates. I have analyzed this argument in a number of gas and electric rate cases over the years and it is flawed. The argument rests on data such as the American Community Survey (ACS) or other Census data. The most important flaw in the analysis is to assume that every low income household is poor and that every household represents an electric customer. Both of these assumptions are incorrect and it is difficult to actually measure the net of low income poverty households who are utility customers and who pay their own electric bills. A simple but realistic example for TEP will illustrate these issues. From the ACS data we know that more than half of the occupied housing units are rented. This is not unusual for an area with a large state university as I have analyzed data for Columbus, Ohio (Ohio State University) using census block group data and GIS meter data in responding to claims about unserved poverty households. It is also not unusual for college students to be low income and qualify as low income households of unrelated individuals when they rent apartments. If they live in dorms each room is a low income housing unit. As a result in both of these

cases, on-campus housing and off-campus apartments the students would be below the poverty level for income and many of those will either not have a utility bill or will not pay for electricity from their limited income. The ones who live off-campus will be the only ones with the potential electric bill and they are likely to be very low use customers based on their lifestyle and there are typically multiple low income persons in an apartment. They are not however poor. In addition to the impact of college students there are low income individuals who live in group homes, individuals who do not pay their own electric bill, low income households who are not poor and so forth. Importantly, there is no economic rationale for potentially eligible low income, poverty households to refuse to participate in a program that is widely known and provides a benefit to reduce bill impacts.

Q. Witness Zwick and others discuss the cost differences for multi-family dwellings as a rationale for opposing increased customer charges. Is that analysis correct?

A. No. This is also a common argument but related to the lower use by apartments and the supposed lower costs. It is not correct that urban area utility costs are lower than suburban or even rural areas. The reason is quite simple. Urban area costs are often higher than suburban or rural areas. ConEd serves the most urban service territory in the country with more multi-family dwellings than most utilities and is one of the highest delivery cost utilities. The explanation is really quite simple. It is more costly to provide underground service in an urban area than in suburbs because of the requirements to use conduit, place facilities in the street, use underground transformers and so forth. In suburbs, the transformers are typically pad mount and conductor is direct buried cable and typically in right of way granted by easement that is not in the street. Finally, for rural or suburban installation projects that require long runs of conductor that cannot be paid for with higher use than apartments, line extension polices would require a contribution in aid of construction.

In addition to capital costs, maintenance costs in urban areas are also more expensive because of the underground facilities that share common space with other utilities under the street.

Figure 1 Example of an Urban Street Cut

Figure 1 is a picture of an urban street cut that illustrates the co-location of utility facilities under the street in urban areas. This includes utility service such as natural gas pipe, electric conduit, water and sewer lines, telephone lines and cable service. The co-location of these facilities requires very different levels of security, different access requirements including street cuts and hand digging and other more costly requirements resulting from local regulations. Taken together it is simply not true that urban costs are lower than suburban costs. It is possible that they are actually higher meaning that the cross subsidy would flow from suburban customers to urban apartment dwellers.

Q. Witness Zwick uses Arizona RECS data to compare low income use to poverty usage in the TEP service area. Is this reasonable?

A. No. The TEP data has been filed in this case. It does not represent a sample but the entire

population of actual eligible low income families and households served on the Lifeline rates.

Q. Do Lifeline customers have nearly identical kWh usage as regular customers?

A. Yes. In total Lifeline customers have nearly the same bill distribution except for the high use tail of the non-Lifeline customer distribution. If the highest use bills above 2,000 kWhs per month are removed from the distribution (about 5.7% of non-Lifeline bills) the distributions are nearly identical and the lowest usage bills below 200 kWhs per month represent a larger percentage of bills for regular customers than for Lifeline customers with Lifeline customers having over 5 percentage points fewer bills. The point is that low income customers are not necessarily low usage customers; in fact there little correlation between being low income and having low usage.

Q. RUCO witness Huber states that it is a faulty premise that fixed costs should be recovered in fixed charges. Please comment on this assertion.

A. Witness Huber is incorrect as a matter of economic theory of efficient rates and the requirement that rates be just, reasonable and non-discriminatory. As I have discussed above, throughout the history of the electric utility industry rate practitioners have recognized the need to recover fixed customer costs in fixed charges. And even fixed demand costs in kW demand charges. The Doherty rate discussed above is a prime example of the multi-part rate schedule developed by a utility practitioner. Historically, electricity was billed as a fixed sum per customer per billing period but the fixed charge was not the same for all customers. Energy was not even metered as is the practice today for some loads. The other and more common rate option prior to metering energy was the flat demand rate that was fixed based on the capacity of the loads being served. The

concept of customer related costs begin in 1891[21] with the discussion of the role of meter rental charges and the development of costs related solely to the customer. Similar cost analysis including customer costs and meter costs was developed in 1896[22]. In both of these articles the key point is that just and equitable rates require small use customers to pay the fixed customer related costs and not be subsidized by larger use or higher load factor customers.

It is only through the use of fixed charges to recover fixed costs that the matching principle of rates is satisfied. This principle is important since it is required to provide a reasonable opportunity to earn the allowed return and is required for reasonable rates that reflect the cost of service principle. This is the practical side of rates for groups that are not perfectly homogeneous. It is well established that the residential class has grown less homogeneous over the last 100 years—a trend that has accelerated in recent years—increasing the practical requirement that just and reasonable rates recover fixed customer costs in the fixed customer charge. In the past, when residential customers had more homogenous usage, the distinction was less important, and volumetric charges could be used to recover fixed costs, because with similar usage those costs would end up being paid relatively uniformly by the customers. That is no longer the case.

Witness Huber's view is also totally inconsistent with the views of economic theory of efficient rates in a declining cost industry such as electric utilities. In that case the fixed charge would be set to recover all of the fixed embedded costs that exceeded marginal cost. Under 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.

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[21] Walton Clark, "Meter Rents—A Question of Equity and Policy", American Gas Light Association Proceedings, IX (1891) pp. 686-688

[22] A reprint of the 1896 article of W. J. Greene on cost analysis may be found in The Development of Scientific Rates for Electricity Supply, Printed for Private Circulation Only by The Edison Illuminating Company of Detroit, 1915, pp. 23-29 (Available from GOOGLE Books)

Q. Please provide an example illustrating how kWh charges should not be used to recover fixed costs.

A. The idea that rates can be reasonable and recover all fixed costs in kWh charges or even with limited customer charges is not logical as can be shown by a simple example. The utility consists of two customers who have identical facilities to provide generation, transmission and distribution and thus cause the same fixed costs. If the two customers used the exact same kWh and kW demand rate design would be trivial since any set of fixed and variable charges would recover the cost caused by each customer because the two customers are perfectly homogeneous. As soon as the customers use different kWhs with the same demand the customer with more kWhs pays more than the cost he causes and the lower use customer pays less. This very observation was the basis for the early development of a customer cost component and customer charges and the observation prevails still today over 100 years later only it is much more important because 100 years ago the loads were homogeneous with only the intensity of use varying. Today the loads are not homogeneous so the costs vary for customers with the same kWhs, customers with different demands on different components of the system and different kWhs. The only reasonable option is to do away with compromise, two-part rates and recover fixed costs in fixed charges and variable costs in variable charges while still sending appropriate price signals as may be permitted by revenue requirements.

Q. Witness Huber states that the proposal deviates from "common utility practice", please comment on that conclusion.

A. That conclusion is simply wrong. Customer charges are increasing at literally thousands of utilities around the country. There are approximately 3,300 electric utilities in the United States. Of this total the investor owned utilities represent about 6%. His basis for this conclusion is a sample of 51 "decisions" in a report he did not prepare. First, municipal

utilities are typically not regulated by commissions and there are six of the 51 utilities that are municipals. Likewise public utility districts are typically not subject to state commission regulation and three are PUDs. Finally, the Salt River Project is not regulated by the Arizona Corporation Commission. 15 of the cases were settled and the Commissions accepted the settlements. Five decisions were postponed or moved to another docket. This leaves 21 utilities out of 1000s of utilities as the evidentiary support for defining common utility practice. As a practical matter the common utility practice has been to increase customer charges in order to recover fixed costs caused by customers. On that basis alone the common practice that includes IOUs, Cooperatives and Municipal Utilities is to increase customer charges and to reflect customer costs in rates.

Q. Do you have any specific data on how TEP's proposed customer charge compares to other utilities?

A. There are about 1000 electric utilities with residential customer charges equal to or greater than $20 per month[23] as originally proposed by TEP. I understand that TEP is accepting Staff's even lower customer charge of $17.00 as a compromise measure. Because the evidence fully supports a customer charge of at least $20, it certainly supports increasing the customer charge to no less than that proposed by Staff.

Q. Witness Huber provides a list of reasons that customer charges were not approved. Is that applicable in this case?

A. Witness Huber cites six reasons for not increasing the customer charge as given in the report he cites as the basis for his conclusions as follows:

1. Concerns about reduced customer control;
2. Concerns about rate shock;

[23] Utility Rate Database, http://en.openei.org/wiki/Utility_Rate_Database

3. Concerns about inequitable impacts to low usage customers;
4. Concerns about inequitable impacts to low income customers;
5. Concerns about reduced incentives to invest in energy efficiency; and
6. Concerns about inefficient price signals.

Those concerns are not valid in this case. I will address each of these points in turn.

Q. Please address the first point that customers still have significant control over their bill under TEP's proposed customer charge?

A. Yes. The proposed rates still provide the customer control over the bill unless the customer uses zero kWh because the energy charges are still significant. Importantly, the median use customer (regular or low income) uses over 500 kWhs per month and as a result maintains control over the most significant part of the bill. The largest exception to this is for solar DG customers where over half the bills are zero. In that case the higher charge is fully justified on a cost of service basis since these customers make no contribution to delivery service but use more of that service than the typical customer.

Q. Please address Mr. Huber's "rate shock" contention.

A. Rate shock is nothing more than a convenient phrase to use when there is no real rationale for opposing an increase. The term rate shock refers to large over-all utility increases. The term was coined to address the impact of costly baseload nuclear plant additions to rate base that would add billions of dollars to the rate base. There is no connotation in which an increase in rates of $0.33 per day per customer can be considered rate shock. The term is misapplied in this context. Further, customers typically care about their overall bill, not about specific components such as the customer charge. If "rate shock" is to be considered, the proper frame of reference is the overall bill. Looking at one component—here the

customer charge—is misleading because it misses the offsetting impact to the volumetric charge.

Q. Please address the impact of the proposed customer charge to low use customers.

A. The issue of low-use customer impacts has been discussed above, but essentially the current rates and low customer charge are inequitable because they do not recover costs caused by low-use customers. Many of the low-use customers are seasonal and DG customers and are receiving large subsidies under the current rate.

Q. Please address the impact of the customer charge to low income customers.

A. I have also discussed the issue of low income customer impacts above. As I have explained, it is incorrect to equate low income and low use customers. As I have explained there is not economic or rate rationale to limit customer charges to address low income bill issues. The optimal policy is to have one rate for all customers and provide low income assistance outside of a rate mechanism because a one size fits all approach results in a program that really does not fit anyone.

Q. What about energy efficiency and price signals?

A. The issue of incentives for conservation and inefficient price signals are the same issue. In this case the efficient price signal would be an energy charge that is much lower than the resulting energy charges after the full customer charge increase. Simply, efficient pricing sets the volumetric price at marginal cost and the remaining revenue requirement in fixed charges. This point has been made in the New York REV proceeding in a report prepared for NYSERDA. The rate recommendation states:

"Q: Why is it important to collect embedded costs with network subscription charges?

A: *Mispriced components lead to inefficient investment and operation decisions by customers*. Without a size-based access charge to recover residual embedded costs, higher volumetric rates are required which charge customers more than the marginal costs for energy consumption. Access charges reduce uneconomic bypass and *lessens social welfare loss*.

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. This strategy could enable the evolution of different utility business models, such as separating the utility into an independent distribution system operator that plans and operates the grid and an asset company that uses asset-backed financing and a fixed revenue stream based on the network subscription charge to finance and maintain the network at a lower cost."[24] (Emphasis added.)

As this statement notes higher energy charges result in uneconomic bypass including DG, DER and energy efficiency. By charging rates that exceed marginal cost even including plausible values for externalities, the RUCO proposal and indeed the proposals of all the opponents of the TEP customer charge increase are supporting a significant loss in social welfare to support their own end-use opportunities.

Q. Have you addressed witness Huber's cost causation argument that concludes the proposed charge is not based on cost causation?

A. Yes. I have demonstrated above that the minimum system concept is a necessary condition for rates to reflect cost causation. The evidence of that requirement is irrefutable.

[24] Full Value Tariff Design and Retail Rate Choices Prepared for: New York State Energy Research and Development Authority and New York State Department of Public Service April 18, 2016, Energy and Environmental Economics, Inc., p. 18

Q. What about the arguments that witness Huber offers against the minimum system use to classify distribution costs as customer related?

A. Witness Huber has claimed that the method is flawed because it "assumes that the configuration of the distribution network is a given."[25] No such assumption is required. The distribution network is always built in a way to provide safe and reliable service. Regardless of the actual amounts of cost or the actual physical configuration of the network a portion based on the smallest size of equipment that is actually installed is classified as customer. As I have discussed above, the method is required to reflect the relative costs and physical amounts of network assets used by each class of customer. No other method of allocating distribution system plant costs can properly reflect the actual physical assets used by each class.

Q. Do you have empirical data to support the conclusion that distribution costs are directly tied to customers?

A. Yes. This point applies to TEP based on several different types of Company specific empirical analysis. Using distribution plant data for the twenty year period from 1995 to 2015 and customer and demand data for the same period, I have tested empirically the cost causation for this asset class. Using gross plant each year as the dependent variable and customers as the independent variable, with the intercept term set to zero, customers explained 95 percent of the variation in the dependent variable distribution plant costs in accounts 364-368. That value increases to 97 percent if we use customers and demand as measured by MVA of substation capacity. In both analyses the F-Statistics and the t-statistics are significant meaning that we can reject the hypothesis that the variables are no different than zero.

[25] Huber Direct Testimony at p. 16

Further, TEP provided data on the number of distribution transformers (Account 368) and the number of transformers used by the residential class. Table 1 below has three columns of data: actual transformers, minimum system allocation and NCP demand allocation.

Table 1 Physical Number of Distribution Transformers

	Actual Transformers	Minimum System*	Class NCP*
Total	72,270	Allocation	Allocation
Residential	59,771	60,056	37,414
All Other	12,559	12,214	34,856

*Values developed from TEP base cost of service study allocation factors.

As the table illustrates, the use of the minimum system closely matches the actual mix of class transformers used in the cost of service study. The same conclusion applies to the physical requirements for the other distribution accounts as well. This is consistent with findings in other cost of service studies where this analysis has been conducted to verify the minimum system concept. With the support of empirical evidence, theoretical analysis and econometric analysis of productivity and so forth, there is no valid opposition to the TEP proposed customer charge or its cost causation tracking based on the RUCO evidence provided by witness Huber.

Q. What about the customer benefits argument that witness Huber asserts as a basis for limiting the customer charge?

A. The benefits received argument has no basis for setting rates as it essentially penalizes higher load factor customers who cause the same delivery costs as a low load factor customer. The fallacy of this argument was a central element in the rate strategies used to grow electric utilities to take advantage of economies of scale throughout most of the twentieth century. Namely, the elasticity of demand increases at higher usage levels. In addition smaller customers actually cause more costs than larger customers because of

economies of scale. The fundamental point is that there is no basis for measuring benefits and theoretically the highest benefits accrue to the least elastic uses because that results in the highest consumer surplus. If a customer benefits from a service at any level, it can be said that that customer causes costs and should pay those costs. In this case that means a customer charge as proposed by TEP. Even at that charge, the rates will not be economically efficient for residential customers as noted above.

Q. Is there a rationale for keeping the customer charge low to protect low income customers as suggested by witness Huber?

A. No. I have discussed this objection in detail above. Again, low usage customers and low income customers are not identical groups. As I have shown, low income customers actually have a fairly normal distribution of usage. Thus, Mr. Huber's argument is flawed and results in large losses in social welfare for a very few customers who are actually poverty level users and use small amounts of electricity. Targeted assistance as I noted is far more efficient and consistent with more economically efficient rates.

Q. Is earnings risk reduced by higher customer charges as claimed by witness Huber?

A. No. Even with the proposed customer charge increase there is also an increase in the average volumetric charge and in the average bill. If the usage pattern changes from the current pattern through DER or through EE, the system earnings will decline more than currently. This decline results whether customers respond to marginal price or to the total bill. It is also critical to understand the risk profile of comparable companies before even attempting to opine on the potential for reduced equity return based on risk. Witness Huber provides no discussion of comparable companies and the revenue mechanisms employed by their regulators. For that reason alone no conclusion regarding the risk impact on earnings is valid.

Q. RUCO witness Huber states that lower users contribute less to overall system costs. Is that statement correct?

A. No. It actually cost more per unit to serve smaller users because per unit cost of capacity for delivery declines as the size of assets serves increasing load. This is because of economies of scale. Also, on a per unit cost basis low use customers have lower load factors than larger users based on TEP load research data.

Q. Please comment on the testimony of witness Baatz for sweep as it relates to customer costs and customer charges.

A. Witness Baatz makes virtually the same arguments as witness Huber as it relates to the level of the customer charge and the minimum system. Essentially the errors discussed above related to witness Huber are also found in witness Baatz testimony. Witness Baatz states the minimum system is improperly defined. On the contrary, determination of the minimum system is not subjective and is based on the actual distribution standards used by TEP. Witness Baatz states the system is hypothetical and that is not true because TEP actually installs minimum sized facilities. Witness Baatz seeks support from Bonbright for his opposition but in fact no such support can be found if the total context of Bonbright is included rather than selectively lifting one sentence from his work as discussed above. Witness Baatz also cites a 2000 report prepared by the Regulatory Assistance Project as support for the opposition to various support for the customer charge. First, that report is dated and did not have the advantage of the latest empirical research as noted above. Second, that report relies on a statement that thirty states use this "general approach".[26] That statement is not supported by any study or by any survey. The simple fact is that each rate case is a new opportunity for regulators to review the evidence in the case and the

[26] Weston, Fredrick. 2000. "Charging for Distribution Utility Services: Issues in Rate Design." Regulatory Assistance Project. http://pubs.naruc.org/pub/536F0210-2354-D714-51CF-037E9E00A724, p. 30

evidence in this case proves that the basic customer method cannot reflect cost causation and is therefore unacceptable for use in this case.

Q. Witness Baatz states that the minimum system is a "radical shift away from previously approved cost of service methods". Please comment.

A. Rate cases represent an opportunity to improve cost of service studies to reflect cost causation. The minimum system is one such improvement. It is based on TEP recognizing that prior cost studies did not adequately reflect cost causation and that is the ultimate objective of a cost study. If the old method had continued the residential class would have been allocated only 62.6% of the transformers they actually use and even less costs for those transformers because of the economies of scale in transformer costs reflected in revenue requirements. This is just one example of the improvement in reflecting cost causation and applies to all of the accounts 364-368. The proposal is nothing more than TEP evolving its cost study to reflect cost causation more accurately. That same conclusion applies to rate design as the mixed competitive and monopoly model requires rates to reflect cost causation or the model makes those customers using the full basket of utility services will pay an ever increasing share of utility fixed costs that they do not cause, which will produce rates that are not just and reasonable.

Q. Witness Baatz makes other arguments about cost causation such as costs for apartments or rural area service costs. Please respond.

A. As with other arguments in the testimony, there is nothing new in witness Baatz testimony. The arguments are not sound as I have discussed in detail above.

Q. Is the TEP rate proposal an SFV rate as discussed by witness Baatz?

A. No. Energy charges continue to recover significant amounts fixed costs so the rate is decidedly not a Straight Fixed Variable ("SFV") rate.

Q. Witness Baatz argues that fixed costs recovery in fixed charges has "little precedent in the commercial world". Please comment.

A. This is an extremely old argument that has been rebutted in the literature as early as 1938 in the monograph Service Charges in Gas and Electric Rates by Hubert Frank Havlik who devoted almost three pages to the subject of the commercial precedent and concludes "These instances show that service charges appear in other than utility industries, and that *demand and customer costs* affect the pricing of the service or commodity."[27] This is not the only such discussion as a recent blog post by Severin Borenstein from the Haas School at the University of California Berkeley who states the argument as "No company in a real market would ever price that way." His conclusion is that "In almost every instance, however, the claim is both incorrect and irrelevant."[28] Witness Baatz views are neither credible nor sound as it relates to the nature and recovery of these costs.

Q. Witness Baatz also makes an equity argument in opposition to customer charges by defining equity based on kWh use. Please comment.

A. The concept of equity is not defined on a kWh basis but on a cost causation basis. The logic is simple. If two customers cause the same costs and pay the same rates that would reflect equitable treatment. As I have shown above, customers regardless of kWh use cause the same customer costs for service within a class such as residential customers- either full or partial requirements service. Alfred Kahn also reaches the same conclusion I have

[27] Service Charges in Gas and Electric Rates, Hubert Frank Havlik, Columbia University Press, New York, 1938, p.98

[28] "Is Electricity Pricing Different from "Real Markets"? Should It Be?", Posted on June 13, 2016 by Severin Borenstein, Berkeley-Haas Insights, https://energyathaas.wordpress.com/2016/06/13/is-electricity-pricing-different-from-real-... 6/13/2016

reached when he concludes "for those segments of demand that do not have the requisite high elasticity—prices based on fully distributed costs have much to recommend them."[29] Kahn also concludes that customers typically recognize the equity of paying charges based on cost of service.[30] Since customer costs do not vary with kWh consumption, equity actually requires that all customers, regardless of kWh consumption, pay a charge equal to the costs. It is witness Baatz proposal that is inequitable not the TEP proposal that moves in the necessary direction of equity.

Q. Does the customer charge create a higher hurdle for energy efficiency investment for low income customers as claimed by witness Baatz?

A. No. This statement is nonsense. The customer has the same return as everyone else based on a saved kWh in the energy tier where marginal consumption occurs. However, the use of non-cost based inverted rates results in low use customers facing a lower per kWh return on their investment than other companies. True concern for the low income conservation impact of rate design is inconsistent with witness Baatz opposition to eliminating the tiers in rates.

Q. Witness Kobor states "TEP's proposal to double basic service charges for residential and small commercial customers and to reduce the number of residential tiers is not reflective of "modern" rate design. Instead, it reflects regressive actions that will undermine commission policy." Please comment.

A. As I have noted above common utility practice including all electric utilities in the country is to have higher customer charges as about 1000 of the three odd thousand electric utilities are $20 dollars or greater. This is the essence of a fully unbundled rate structure that is a prerequisite for utility operation in a mixed monopoly and competition model. Failure to

[29] Kahn, Op. Cit. p. 158
[30] P. 158

develop reasonable and modern rates results in the majority of customers subsidizing DG customers as the cost studies discussed below prove. In fact, it is the current two part rate that has been a compromise for over a century. As for undermining Commission policy witness Kobor does not really justify how policy is undermined except to say there may be less DER and EE. The important points in rate design are found in PURPA whose purposes are as follows:

1. Conservation of energy supplied by electric utilities,
2. Optimal efficiency of electric utility facilities and resources, and
3. Equitable rates for electric consumers (PURPA section 101).

These three purposes provide Federal guidance for how rates should be designed. The equitable rates purpose is only satisfied by reflecting cost causation in the customer charge and demand and TOU based energy charges as fundamental principles of rate design. The required basis for cost of service under PURPA is that rates reflect cost of service and measure the impact of customers, demand and energy on the determination of costs. TEP performed such a study to inform its rate design. In addition, the costs studies discussed below adhere to that standard as well. Witness Kobor must define conservation as an absolute reduction in electric sales. That is an incorrect definition. If the definition of conservation used by Congress had been intended to be different from the definition "Conservation is the act of preserving, guarding or protecting; wise use" it would have had the opportunity to define the term among other definitions of the standard. Wise use coupled with optimal efficiency of facilities and resources is only achievable when rates reflect cost of service and any artificial subsidies such as those offered to DG under net metering and banking are eliminated. The simple fact is that the value of rooftop solar is at most the price paid for utility scale solar, adjusted for the net effect of rooftop solar DG on distribution system losses, which may be zero. Nothing in the TEP proposals undermines Commission policy. Further adopting the TEP proposals as filed begin to eliminate the

undue discrimination in rates as demonstrated above and in the cost of service studies discussed below. The evidence shows that witness Kobor's statement is negative rhetoric designed to achieve the type of rent-seeking that the Commission must not permit.

Q. Witness Kobor also opposes the use of the minimum system method in the cost study. Is the opposition based on sound analysis and evidence?

A. No. I have discussed most of the points made by witness Kobor above and have demonstrated that her arguments cannot be supported by any evidence she has provided. Her conclusions are simply incorrect for all the reasons I have discussed in detail above. The absence of logic is best demonstrated by her conclusion that because the basic customer method produces lower customer charges the customer charges in the cost study "significantly over-allocates costs to the customer function."[31] Aside from the logical flaw that two different methods produce different results proves the higher number is wrong, the argument suffers from another fatal logical error. This conclusion assumes that a method she proposes that is not recognized by NARUC or any of the theoretical treatises on rates such as Caywood, Bary, Suelflow etc. is the correct method. It is not. In addition the evidence above related specifically to TEP proves quantitatively and qualitatively that the basic customer method can never be cost based. The minimum system is cost based.

Q. Please summarize your conclusions related to the cause of customer costs and the level of the customer charge.

A. Customer costs based on cost causation must include the customer component of the distribution system in Accounts 364 – 368. I show conclusively that inclusion of the minimum system is a necessary condition for reflecting cost causation. I have demonstrated that the arguments of the parties who oppose the minimum system all suffer

[31] Kobor at p. 72.

from some incorrect analysis and in general are unsupported by their arguments for alternative methods of calculating customer costs. I also show that modern rate design cannot be equitable or efficient absent a customer charge as proposed by TEP. I recommend that the Commission adopt the cost study as proposed and the proposed customer charges in order to have just and reasonable rates that meet the requirement of providing the Company a reasonable opportunity to earn the allowed return.

III. Economics of Serving Full and Partial Requirements Service Customers.

Q. Please define the terms full and partial requirements customers.

A. A full requirements service customer is a customer who elects to use the full bundle of utility services on a continuous basis and acquires no utility related services from another provider. In the case of an electric customer this means that the customer uses the full scope of production, transmission, distribution and customer services from the utility in a seamless package represented by the delivery of capacity and energy to the customer as required by the customer. A partial requirements service customer is a customer who elects to select the particular components of the utility service to be used when the customer elects to use the utility service and to use other non-utility sources for all or a portion of the some of the standard utility services to meet their demand for energy or capacity or some combination of the two requirements. Solar DG customers are one type of partial requirements customer. Partial requirements customers essentially are former full requirements customers who elect to use the utility for services such as back-up/standby service, maintenance service or supplemental service or some combination of all of these services.

Q. Do partial requirements customers differ from each other and from full requirements customers?

A. Yes. Partial requirements customers differ both from full requirements customers and from each other depending on the non-utility services they purchase because the demand and energy load shapes the utility must stand ready to serve differ and in some case differ dramatically. For example, some partial requirements services provide baseload service leaving the utility to provide supplemental peaking services and may be viewed as low load factor customers for the utility. Other partial requirements services are peaking in nature and leave the utility to provide baseload service and may be viewed as high load factor customers for the utility. Each different service has different cost characteristics based on the cost the utility incurs to serve the customer.

Every solar DG customer differs from customers who use cogeneration and cogeneration customers differ based on technology. They also differ based on the underlying total hourly demand for electricity. For example, when a residential customer changes from full requirements to partial requirements, the underlying load characteristics of the dwelling do not change nor do the local facilities installed to serve that customer change. As an example, the utility cannot change the service line or the transformer to serve that customer because those were sized to serve the maximum load of the customer whenever it occurs. The load measured in kWh and kW imposed on the utility does change however. The customer may use less energy but may still require the same or more kW capacity for delivery service and may even require the same capacity for production and transmission depending on a number of factors associated with the customer's non-utility supply source. Since different technologies have different supply characteristics every different source will have a different impact. In some cases, that impact is a function of system characteristics in others it is a function of technology or some of both. If a new customer comes on the system as a partial requirements customer, the utility system planners must

still provide for the maximum service that a partial requirements customer may impose when the customer's non-utility source of supply is not available. The important point is that one cannot assume that partial requirements customers cause fewer costs, and in some cases it may even increase. To determine cost causation requires an understanding of the type and timing of the services provided by the utility. Finally, it is critically important to recognize that utility capacity requirements are not the same for each component of utility service. Appendix B to this rebuttal testimony is a copy of my white paper "Smart Rates for Smart Utilities" that provides a detailed discussion of many of the concepts related to unbundled rates and the necessity for each rate component.

Since the issue of capacity savings cannot be determined based solely on one measure of capacity as discussed later in this rebuttal testimony, it is impossible to conclude that there are capacity benefits for each measure of capacity- production, transmission and distribution- for partial requirements service. The capacity obligation associated with the DG customer is typically the same or as demonstrated in the cost studies below greater than the delivery requirements for a full requirements customer and is based on the expected capacity of the distribution system used by the premises which may and usually does occur outside the peak load period.

Q. In the context of a rate case is it possible to determine the change in revenue requirements resulting from a customer shifting to partial requirements service?

A. Yes. I have made just such a determination in the cost studies provided below. The values in a cost study may or may not equal the actual avoided costs that should be the maximum allowable credit for a solar DG customer. The avoided cost to the utility will generally be lower than the embedded cost credit because of the sunk cost and lumpy nature of utility costs results in higher average costs than avoided cost. Given that utilities exhibit economies of scale, this would imply that marginal cost is below average costs. Further,

the marginal cost of a load increment differs from the marginal cost of a load decrement (avoided costs) because of the lumpy investments and the sunk costs of a utility. A simple example will illustrate this point. If a new customer is added to the system that requires 8 kW of delivery capacity the utility adds a 10 kVa transformer to serve the load of that customer along with the necessary conductor and feeder capacity as needed. If a few years later that customer reduces its demand by 2 kW the utility does not change out the transformer and ultimately cannot replace that transformer at the end of its useful life with a smaller transformer. This same logic applies in the context of a substation and its transformers. If the total load on a substation transformer is 8 MVA the utility will install a 10 MVA transformer to serve the load. If that load in every hour of the year is reduced by 25% the substation still requires a 10 MVA transformer to serve the peak loads. If the lower load periods are significantly below 5 MVA, energy losses increase as a percent of load and the utility may actually add a 5MVA transformer to the substation to use in low load periods and switching equipment to use the larger transformer when loads are higher. In either case there are no avoided costs as the result of the drop in load. The avoided cost in the first case is zero and in the second case there are added capacity costs reduced by the reduction in lost energy costs for a net of no avoided costs but there is a cost shift in the second case.

Q. Why would a utility need a separate rate for partial requirements customers?

A. A separate rate for partial requirements customers is needed when some customers use the system differently than other customers who have the same end-use loads. Different usage patterns result from how a partial requirements customer uses the system.

Q. Do solar DG customers use the system differently than full requirements customers?

A. Yes. Solar DG customers provide an excellent example of a group of residential customers that use the system very differently from full requirements customers. These customers use the system for much more than the delivery of kWhs they consume when solar DG is not available or inadequate to serve the total hourly load. Some differences include the use of the system for the sale of excess kWhs back to the system. Under net metering with a banking provision solar DG customers use the system for virtual storage just as if they had a very large battery that would allow them to put kWhs in the battery in low load periods and draw them out of storage to offset purchases in high cost periods. This is a service that is free under net metering but is not free from subsidy from other customers who pay for the storage service and the price differential between high load, high cost periods and low load, low cost periods. Other customers also pay for the losses associated with the delivery to storage and the delivery back to the customer under net metering where there is no loss adjustment associated with the transaction.

Q. Please address class NCP for solar DG customers.

A. Solar DG customers also use the distribution system differently. The reason that the distribution system is used differently is that while there is natural diversity in customer loads that produce the class load NCP, there is no natural diversity at the class NCP for solar DG sales of excess generation. The maximum output of all of the solar DG customers occurs at the same time because the DG facilities are all or predominately designed to maximize kWh production and are fixed axis solar DG installations. The peak production occurs on the coolest day in the spring and at mid-day. There is no diversity in the sense that some customers peak later or on a different day because of the inherent technological and operating characteristics of solar DG. In a sense this peak is like the gas system peak that occurs for all heating customers on the same day based on

the weather conditions. This means that it is possible that the class NCP for solar DG actually occurs on a day not based on load but based on delivery of power back to the grid. That is the case for TEP where the delivery NCP is greater than the load NCP. The solar class NCP occurs at noon in March or April when almost twice as much power is delivered to the system than the solar class contribution to the load NCP on the hottest day in the summer. Figure 2 below illustrates the nature of the generation delivery to the utility system for three days in April where the highest delivery is 43,429 kW at 13:00 hours using the hour ended concept used by utility dispatch.

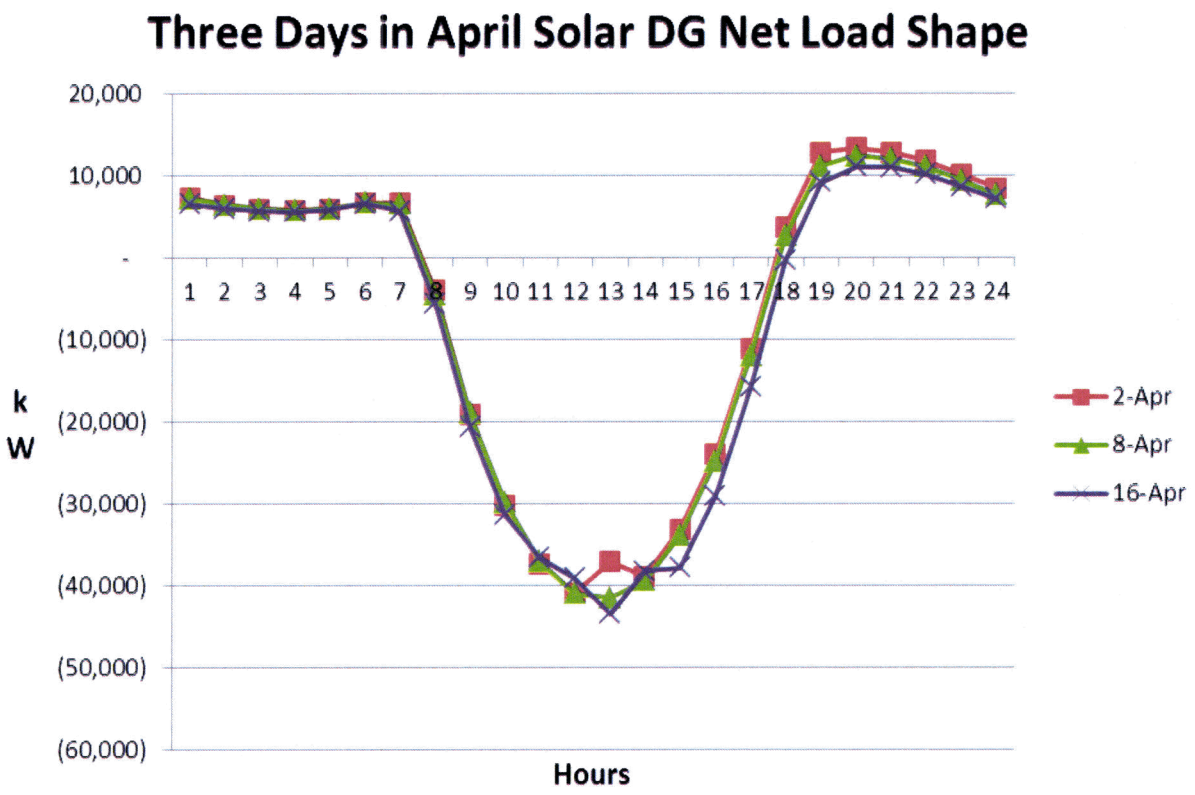

Figure 2 April Solar DG Net Load Shape

The distribution system must be able to accommodate bi-directional delivery service and serve the load at which ever maximum occurs- either load NCP or generation NCP. This high load also raises marginal losses on the local facilities that impact the net delivered

power from solar DG for the grid. This is very different from how full requirements customers use the grid.

Q. How should delivery costs be allocated to DG customers?

A. To properly allocate delivery service costs to DG customers it is necessary to recognize the actual class NCP. It also means that for customers who respond to the energy price signal and size their system to minimize the utility bill there are no possible distribution cost savings.

Q. Are there other ways that Solar DG customers are different?

A. Yes. When kWs are sent back to the system in these low load periods the system power factor deteriorates because solar generation produces no vars. In order to resolve the lower power factor associated with solar DG it is inevitable that distribution costs will increase as the utility installs switched capacitors to manage the system power factor. The alternative to the low power factor is to require smart inverters as part of the interconnection standard. This is similar to the provisions in rates for larger customers that either bill customers on a kVa basis or include a power factor adjustment provision that recognizes lower power factor has a cost as in the large customer rates for TEP.

There are other uses that solar customers make of the system such as synchronization of solar generation with the grid, in rush current, supplemental service and backup service. These services all result in differences between the residential solar DG customers and full requirements customers. For example when a full requirements customer uses in rush current to start a motor load there is also kWh use that is billed. For a solar DG customer there is no kWh use when the solar DG is operating and meeting the load but the in rush current is used. The pattern of supplemental service is such that solar DG customers require utility service in some of the highest cost hours based on the limited energy from

solar DG in those hours. These are all unbundled services used by solar DG some of which they do not compensate the utility for the costs they cause and others which they pay less than the full costs under the two-part rate.

Q. Is the difference in system use recognized generally by industry observers?

A. Yes. This concept is widely recognized. For example the following quotation from a blog post from the Haas Energy Institute provides one such example:

"The reality is that a customer who consumes 300 kWh in a month is imposing very different costs on the system than a customer who consumes 1500 kWh over some hours and also injects 1200 kWh into the grid during other hours. NEM treats them the same. That may have been a *convenient benign fiction* back when solar PV barely existed. But today *it is a costly distortion that has the potential to create huge economic inefficiencies and unfairly shift billions of dollars in costs among customers*."[32] (Emphasis added.)

Q. Is there a way to illustrate how differently DG customers use the system compared to full requirements customers based on TEP load data?

A. Yes. I have used TEP load research data for the residential class from the cost study and the load shape for TEP solar DG customers developed originally in IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION DOCKET NO. E-00000J-14-0023 and used below in the cost of service studies based on actual TEP billing data and actual customer solar DG capacity and modeled to match actual hourly load profiles for solar DG customers based on residential load research data. Based on that data I have calculated the monthly, class NCP load factors for full requirements residential customers and for solar DG customers.

[32] Blog Post at Energy Institute at Hass Energy "Billing Tweaks Don't Make Net Metering Good Policy" Posted on January 4, 2016 by Severin Borenstein

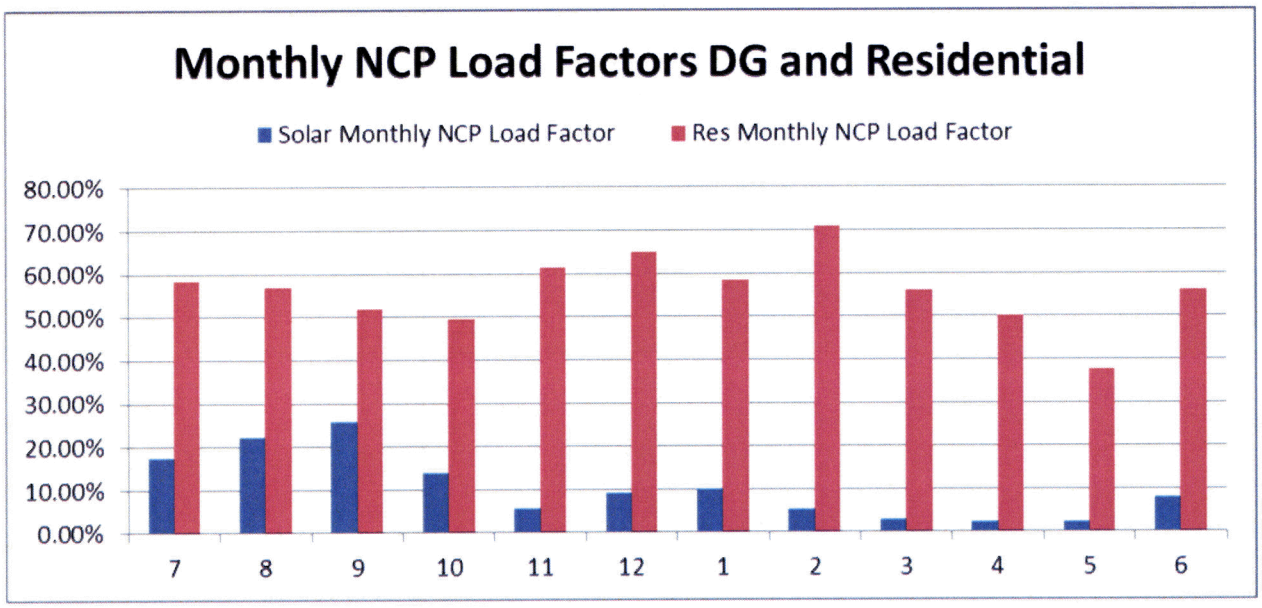

Figure 3 Monthly NCP Load Factors DG and Residential

As Figure 3 illustrates, solar DG customers actually use the system very differently than full requirements customers. In particular, the data shows that DG customers as a class have a lower load factor in every month of the year when compared to full requirements customers. The solar class NCP load factor is consistently less than half of the load factor of full requirements customers and the same result would occur if the data was on an individual customer basis. The second observation is that solar DG customers use more energy in the summer months to supplement their solar DG output as shown by their higher class NCP load factors and the higher system loads. This conclusion is not surprising given the higher summer loads and the reduced DG output associated with ambient temperature. This data contradicts the various claims that TEP has not used their own data to demonstrate how solar DG customers use the system differently than other customers. In addition to this data, the cost of service studies in the next section also demonstrate that TEP based data is used to demonstrate the conclusions related to DG solar proposals.

IV. Cost of Service Study Results.

Q. Please describe the cost of service studies developed in this case.

A. There is no practical way to assess the costs caused or the revenue requirements for full and partial requirements customers without developing a cost of service study that identifies these two classes of residential customers in separate classes for fixed costs and in separate studies for variable energy related costs. In order to respond to he claims made by solar advocates in their direct testimony, I have prepared three different cost studies to allocate the fixed costs of TEP based on the cost study filed in the current TEP rate case. I say fixed costs because the three studies produce results that only allocate costs that are classified as customer or demand costs and do not include any costs classified as energy. I will refer to these three studies collectively as the fixed cost studies. The energy cost studies use hourly costs for full and partial requirement customers to assess the energy related costs and include an analysis of marginal energy costs for each category of residential customers.

Q. Please describe the three fixed cost studies.

A. Based on a decision by the Public Service Commission of Utah in Docket No. 14-035-114 issued November 10, 2015, the Utah PSC adopted a methodology of comparing two cost studies to determine the costs of serving solar customers for ratemaking purposes. The first cost study is the standard cost study with the solar NEM customers' allocated costs just like the residential class based on actual load characteristics of the class. The second study that Utah refers to as counterfactual cost study (CFCOS) assumes that the solar customers did not adopt DG but rather were full requirements customers allocated costs in the same way as the residential class. This study is essentially an embedded cost study that assumes all other things being equal except for the addition of solar PV at the

customer premises. By comparing these two studies it is possible to identify the way costs change for both full and partial requirements customers assuming that the load characteristics in terms of both load and delivery capacity requirements are no different. All other things are not equal when viewed from the factors that cause costs. Since we know that the load characteristics are not the same, I recommend a separate class for evaluating the embedded costs of solar DG customers rather than using the counterfactual study alone with its inherently biased assumption about cost causation. That is the third fixed cost study I have included.

For each cost study we use the same fixed costs for the system based on the 2015 rate case costs as filed in the TEP cost study. Those fixed costs are allocated using the same basic methodology of average and excess for production costs and the minimum system customer costs and class NCP for demand related delivery costs. We also use the same customer cost allocations. Using the same customer cost allocations is a conservative approach because TEP has made no effort to account for the higher level of transaction costs for solar DG customers associated with net energy metering storage accounting, billing adjustments and other customer service considerations. The study is also conservative because we have made no attempt to identify any system investments designed to address power factor issues or other distribution related investments. There is also no adjustment for higher losses associated with the power factor issue noted above.

Q. Do the cost studies comply with the principle of cost causation?

A. Yes. The studies follow the standard process of functionalization, classification and allocation for each unbundled component of costs. Costs are functionalized as generation, transmission distribution and customers.

The production function consists of the costs of power generation and purchased power. This includes the cost of generating units and fuel for the units. In addition, any cost of

purchased power along with the cost of the delivery of purchased power is also functionalized as production.

The transmission function consists of the assets and expenses associated with the high voltage system used by the power system to interconnect with the grid and to move power from generation to load. In this case, this is allocation of the expense transmission by others.

The distribution function includes the system that connects transmission to loads. Different customers use different components of the distribution system. In recognition of this fact, it is common for the distribution system to be divided into sub-functions such as primary and secondary. In addition, some distribution facilities serve a customer function and are allocated between distribution and customer service accordingly.

The customer service function includes plant and expenses caused by individual customers. Customer service includes meters, service lines, meter reading and billing, for example. It also includes a portion of the distribution system including transformers, conductor and poles.

Q. What is classification?

A. Once costs are functionalized, they must be classified based on the categories customer, demand and energy. The classification step is critical to developing allocation factors that reflect cost causation. In particular, it is imperative to understand not only the accounting basis for costs but the engineering and operational analysis of the system as it is planned, built and operated. This is a particularly important concern when developing costs for customers who use the system differently and who create new costs to accommodate the customers' system impacts.

Q. What are demand costs?

A. Demand costs are those costs that vary with some measure of maximum demand. Measures of maximum demand include coincident peak demand, class non-coincident peak demand and customer non-coincident peak demand.

Q. What are energy costs?

A. Energy costs are those costs that vary directly with the production of energy such as fuel costs, other fuel related expenses or purchased power expense.

Q. What are customer costs?

A. Customer costs are those costs that vary with number of customers such as meters and service lines.

Q. Can costs be classified into more than one category?

A. Yes. For example, some distribution costs may have both a demand and a customer cost component.

Q. What is the allocation process?

A. In this step, costs are allocated to customer classes based on a variety of factors. The purpose of allocation is to assign costs to classes in a manner that reflects the factors that cause the costs to be incurred.

Q. Please explain how you developed allocation factors for the study.

A. To develop the allocation factors for the cost study it was necessary to make a basic assumption that the load shape of residential solar DG customers was on average the same load shape as the residential load shape prior to the installation of solar DG. That is

the basic assumption is that the hourly usage pattern for DG customers is no different from the residential class as a whole. The only difference is that solar DG customers provide some of their own energy to satisfy that load shape based on the operation of solar DG.

Using this assumption it is possible to develop a full requirements load shape for solar DG customers using the following data: actual metered kWhs used by solar customers per month, actual excess kWhs delivered to the utility by month, the installed kW capacity of the solar DG, the solar output load shape based on metered data for a fixed axis, south facing solar DG installation, and the load research based residential hourly load shape. With this data the process consisted of a number of logical steps as follows:

1. Using basic number properties of mathematics we calculated the monthly full requirements load for each solar DG customer as the sum of the actual metered kWh plus the monthly solar generation given by the installed capacity times the hourly output load profile less the metered excess energy delivered back to the system. From this calculation we saved both the premises load and the excess energy for use in the various analyses. The value of this calculation cannot produce negative kWh. As a result, we eliminated observations from the data set because the excess kWh sold back to the utility were not possible.
2. Using monthly total energy consumption of the premises and the residential hourly load shape based on the customer's monthly premises use, an hourly load shape of premises use is calculated for each month by taking the ratio of the customer's monthly use to the monthly use of the load shape. In this step we modeled the average solar DG customer as a full requirements customer with the system average load shape.

3. This process was repeated for each residential DG customer and the data aggregated into the DG customers' counter factual load shape for use in the counterfactual cost study.
4. The solar DG class is based on all customers with twelve months of data and a non-zero capacity value. (The Company data set did not have a kW capacity for all of the solar customers and those were excluded from the analysis.)
5. For the counterfactual study the full requirements customer load shape is calculated by subtracting the net load shape of solar DG from the residential load shape used in the base cost study and adding back the full requirements load shape.
6. The solar customer net load shape is the premises hourly load shape minus the generation output shape. The net load shape excluding excess generation is used to develop the solar contribution to the residential load shape for the base fixed cost study.
7. We now have three load profiles for solar DG customers: the counterfactual no solar DG load profile, the generation output profile that allows us to determine distribution system use for exporting power and the solar customer net load profile that allows us to determine distribution system use for system loads.
8. Using this data it is possible to calculate the solar customers demand allocation factors for each fixed cost study and for the energy cost studies.
9. For the counterfactual profile we calculate the residential class Average and Excess Demand (AED) and NCP allocation factors and rerun the cost of service study. We also use the net load profile and calculate the AED and NCP allocation factors using only the net positive energy for AED and the higher of the positive or negative class maximum NCP. The allocation factor for NCP is the absolute value of the class NCP. This is consistent with the maximum requirement for distribution facilities and cost causation.

This data provides a solid, if conservative, basis for assessing the relative revenue requirements differences between the between full and partial requirements customers.

Q. How does one determine the factors that cause costs?

A. In many cases determining cost causation is as simple as asking the question of whether a particular cost changes when some potential allocation factor changes. If a factor causes costs, costs will vary with changes in that factor. For example, if the number of kWhs increases, does the cost of some input such as miles of conductor increase? Since the miles of conductor do not change with kWhs either monthly or annually, energy consumption is not a cause of conductor costs. What we do know is that miles of conductor increases for customers added to the periphery of the system, thus customers are a cause of the cost. We also know that the miles of conductor increases with the growth of the peak load on the conductor and that load may be met by paralleling the system, looping the system, or networking the system. It may also mean building added capacity through expanding the system to a three-phase conductor. This means that some of the cost of conductors is also caused by the demand on the conductor. In any case, the factors driving the cost of conductors are customers and a measure of non-coincident peak demand. Following this logical process allows one to determine cost causation for each element of the system.

Q. How does the AED method for allocating generation capacity impact solar customers?

A. The AED/4CP method used by TEP in the cost study recognizes that low cost energy results from higher capacity costs. Since solar DG customers use lower cost energy from the utility at night they should also pay for a portion of the fixed capacity costs of baseload units in order to buy the low marginal cost energy. While the AED concept was

developed for cost allocation for full requirements customers it results in a more appropriate allocation than would a CP methodology that allocates all capacity costs on a daylight peak hours. Whether the allocation is ultimately reasonable without modification is a fair question for review in rate case proceedings.

Q. Have you used the same data and internal allocation factors as TEP?

A. Generally, the cost studies use the same data for revenue requirements and for allocation factors with the exception of creating a separate column for solar DG customers. We have also changed the use of the minimum system to classify costs. In the base study the solar customers' data and the full requirements customers sum to the same residential allocation factors in the TEP filed study. We have also calculated the rates revenue for each class and those have been included in the study so that the information presented includes the total cost based revenue requirements and the rate of return for each class of service in each study. For the other two studies the total revenue requirements remain the same and only the allocation factors for the solar DG customers have changed. In the counter factual study the customers are allocated the revenue requirement that would result from these customers being full requirements customers. This measures the cost shift between full requirements and partial requirements customers. The counter factual study also shows how the customers shifting to DG contributed to the earned return of the residential class. This recognizes the practical reality of the zero sum nature of the cost study. Increasing the demands of solar DG customers result in lower costs allocated to all the other residential customers.

Q. Please explain the change for the classification of customer costs using the minimum system.

A. In the TEP cost study TEP applied the classification for the minimum system to the costs after using the class NCP to allocate the distribution plant accounts. The use of NCP to allocate distribution plant accounts 364-368 under-allocates distribution plant to residential customers and understates the customer cost component of unbundled rates. After making that methodological change the allocation differs from TEP even though the total revenue requirements remain the same. The result of this change is to allocate more costs to the residential class to reflect the impact of customers on the distribution system costs. It also impacts the unit customer cost component. This adjustment is consistent with the use of the minimum system method as discussed in the NARUC Electric Utility Cost Allocation Manual and the three step cost of service process of functionalization, classification and allocation.

V. Allocation of Fixed Costs – Results of Three Studies.

Q. Please summarize the results of the three fixed cost studies.

A. Table 2 below presents the different revenue requirements for full requirements residential and solar PV residential customers from the cost studies that are attached as Exhibit HEO- 2 Original Base Study, Exhibit HEO- 3 Counterfactual Study, and Exhibit HEO- 4 Solar Class Study. Each Exhibit provides the summary of the allocations, the revenue requirement for each class of service and the earned return by subgroup or class. The base study is identical to the filed TEP study with the exception that solar DG customers are treated as a separate part of the residential class. The counterfactual study assumes that solar DG customers were full requirements customers. The solar class study

treats solar DG customers as if they were a separate class with their own allocation factors and not part of the residential allocation factors.

Table 2 Comparative Fixed Cost Revenue Requirements Embedded Cost of Service Studies

Study	Residential Full	Solar DG Partial	Total Company
Base TEP	$490,392,406	$10,454,255	$958,869,144
Counterfactual	$486,024,537	$14,813,313	$958,869,144
Solar Class	$489,506,144	$11,340,517	$958,869,144
Lowest Revenue	$486,024,537	$10,454,255	

The results of these studies are useful in understanding that solar DG causes significant fixed costs. The total residential class fixed cost revenue requirement is the same $500,870,839 for the base, counterfactual and solar as a separate class cost studies. The difference in the studies relates to the intra class allocation.

The current annual rate revenue excluding Power Supply charges (the base revenue) for residential solar DG customers is $3,352,194. The subsidy may be calculated as the difference between the revenue in the base cost of service or $7,034,647. The implicit subsidy for fixed costs is just over $729[33] per customer for the 9,645 solar DG customers on the lowest fixed cost allocation. That number increases to almost $822[34] when the actual solar class fixed costs are used. In addition to this subsidy, DG customers with net metering and banking have an additional subsidy based on energy costs.

Q. Please explain why the three studies are useful.

A. Since cost of service is a zero sum methodology, all costs must go to some class and any change in allocation to one class must be reflected as an opposite change to one or more

[33] Calculated as ($10,386,841 - $3,352,194)/9645= $729

[34] Calculated as ($11,279, 053 - $3,352,194)/9645= $822

of the other classes. In order to understand the costs for residential DG customers, they must be separated from the full class. The portion of the residential class costs allocated to solar DG customers as part of that class are shown in the base study. The counterfactual study shows the amount of costs that would be allocated to full requirements customers prior to customers choosing to install solar DG and capture the benefits of net metering. Even though no changes occurred in the class cost and no changes occurred in the fixed costs[35] for utility service to the solar DG customers the solar DG customers are allocated less plant than would be allocated before they chose DG as shown by the counterfactual study. This result is not surprising since one would expect that these customers were larger on average than the average customer. Finally by treating solar DG customers as a class they still get less costs than when they were full requirements customers but the portion of plant allocated to them recognizes their higher class NCP based on delivering excess generation.

Q. Is it possible to show how costs changed by each unbundled cost category?

A. Yes. Since the cost of service model develops unbundled costs it is possible to show the aggregate revenue requirements by unbundled cost components. Table 3 below provides the revenue requirements for full requirements customers and for Solar DG customers by function excluding energy.

[35] Solar DG customers still have the same distribution facilities and use the same baseload generation to serve night time loads.

Table 3 Unbundled Costs for Each Cost Studies

	Base Study		Counterfactual Study		Solar Class Study	
	Residential	Solar	Residential	Solar	Residential	Solar
Procurement						
Demand	$164,680,215	$3,679,140	$163,218,631	$5,140,724	$164,729,041	$3,630,314
Energy	$121,172,462	$2,475,186	$119,879,015	$3,768,633	$122,301,113	$1,346,536
Customer	$0	$0	$0	$0	$0	$0
Must Run						
Demand	$23,854,022	$522,353	$23,632,537	$743,838	$23,856,361	$520,014
Energy	$0	$0	$0	$0	$0	$0
Customer	$0	$0	$0	$0	$0	$0
Trans						
Demand	$53,881,096	$917,161	$53,133,475	$1,664,782	$52,751,995	$2,046,262
Energy	$0	$0	$0	$0	$0	$0
Customer	$0	$0	$0	$0	$0	$0
Distribution						
Demand	$45,102,958	$767,740	$44,477,137	$1,393,561	$44,157,806	$1,712,891
Energy	$0	$0	$0	$0	$0	$0
Customer	$55,808,488	$1,432,601	$55,808,488	$1,432,601	$55,808,488	$1,432,601
Cust.						
Demand	$0	$0	$0	$0	$0	$0
Energy	$0	$0	$0	$0	$0	$0
Customer	$25,893,165	$660,075	$25,875,254	$669,174	$25,901,339	$651,900
TOTAL						
Demand	$287,518,292	$5,886,394	$284,461,781	$8,942,905	$285,495,204	$7,909,481
Energy	$121,172,462	$2,475,186	$119,879,015	$3,768,633	$122,301,113	$1,346,536
Customer	$81,701,652	$2,092,675	$81,683,741	$2,101,775	$81,709,827	$2,084,500

The table shows the embedded cost allocated to solar DG customers under each cost study. As would be expected the counterfactual cost study allocates more cost to solar DG customers because they are treated as full requirements customers. All of this data is useful because it shows how solar DG customers shift costs to full requirements customers even though in the rate case period there are no changes in fixed costs associated with solar DG and ratemaking is based on cost of service.

Q. Please provide the calculation of the cost shift to full requirements residential customers from solar dg customers on an embedded cost basis.

A. Table 4 below provides the cost shift based on the difference in revenue requirements for the base case and the solar class case from the counter factual cost study.

Table 4 Cost Shifts Resulting From Customers Adding Solar DG- A Comparison of Customers before Solar DG Installed

	Base Case	Solar Class
Procurement		
Demand	$1,461,585	$1,510,410
Energy	$1,293,447	$2,422,097
Customer	$0	$0
Must Run		
Demand	$221,485	$223,824
Energy	$0	$0
Customer	$0	$0
Trans		
Demand	$747,621	-$381,480
Energy	$0	$0
Customer	$0	$0
Distribution		
Demand	$625,821	-$319,331
Energy	$0	$0
Customer	$0	$0
Cust.		
Demand	$0	$0
Energy	$0	$0
Customer	$9,100	$17,275
SUB-TOTAL		
Demand	$3,056,511	$1,033,423
Energy	$1,293,447	$2,422,097
Customer	$9,100	$17,275
TOTAL	$4,359,058	$3,472,796

As would be expected, the AED allocation of production is lower and there is a larger embedded cost savings for solar customers when they are treated as a separate class. The energy cost shift results from the lower use of energy and hence a lower allocation of base costs allocated on energy such as fuel inventory costs. Two important factors should be noted. As expected, treating solar as a separate class properly increases the cost of delivery related services based on the higher class NCPs from delivery of power to the system. There is also a slight increase in must run demand that is attributable to the variable nature of solar DG generation.

Q. Please summarize the residential class returns in each of the costs studies.

A. Table 5 provides the earned return for both the full requirements residential customers and the partial requirements solar DG customers.

Table 5 Earned Returns by Customer Group and Cost Study

	Residential	Solar
Base	0.06%	-17.62%
Counterfactual	-0.32%	-0.41%
Solar Class	0.12%	-17.02%

The magnitude of the negative return for solar DG customers is further evidence of the undue discrimination between full requirements residential customers and the partial requirements solar DG customers who pay much less for comparable service. This is in spite of the fact that solar DG customers have a production capacity credit of $1.5 million dollars for the current year or $24.64 per kW of solar installed capacity. If that value is adjusted for capacity from solar DG in the peak hour of 5 PM, the implied capacity credit is $141.41 per kW[36]. At that level of credit the embedded cost study essentially assumes

[36] Calculated as 17.4% of capacity times 61,277.33 kW solar installed or 10,681 kW CP production divided into $1.5 million dollars.

that the cost is avoided in the current year. Since that is not the case the embedded cost value of the capacity credit actually exceeds avoided costs.

Q. Why does the solar class study allocate more costs to solar customers than the base study?

A. The unbundled cost components are different based on the fact that the AED/4CP cost methodology allocates generation costs using a demand allocation factor made up of weighted average demand and weighted load NCP. The solar class allocation for generation is less than the allocation under the base case. For the demand related portion of the distribution system, the base case under allocates distribution system costs to the solar DG customers because it uses the load demand rather than the actual maximum demand which is based on delivery demand. The different NCP for delivery compared to the residential class coincident NCP for solar DG customers is less than half of the delivery NCP. That difference is based on the difference in the load diversity and the absence of diversity with respect to excess generation. Thus it is the delivery service that establishes the maximum demand on the distribution system. The net result is that the solar class's allocation increases compared to the base case.

Q. Please discuss the cost of service results.

A. Several conclusions are worth noting. First, the total full requirements, residential class, fixed cost of service is higher for the base case and the solar case than if the solar DG customers had not invested in DG. This results from a cost shift within the class to full requirements customers. Second, all three studies produce a customer charge for both full and partial requirements customers of about $18.00 per month. If the company were to analyze the extra costs associated with solar DG associated with record keeping and billing it is likely that the solar DG charge would be above this average level. Third, it is

critical to understand cost causation on the distribution system results in higher costs for solar DG even without the consideration of the added costs associated with lower power factor, more frequent voltage control events and other impacts on distribution system costs. Fourth, the evidence is conclusive that there are no avoided distribution costs for TEP and likely none for any utility in Arizona given the solar load shapes. Fifth, the magnitude of the base rate charges for solar customers would be much higher than the energy charges for full requirements customers thus necessitating recovery of the fixed charges in demand charges because the kWh charge under a two-part rate would further distort the solar DG sizing decision. Finally, the large negative return provided conclusive evidence that the solar DG customers are subsidized by other customers at amounts that are significant even compared to the modest return from the residential class.

Q. What conclusions do you reach from the cost of service studies as they relate to solar dg, net metering, banking and rates?

A. The conclusions related to cost of service are as follows:

1. Solar DG customers must be treated as a separate class of service in the cost study.
2. The two-part rate with net metering cannot ever produce equitable treatment of full requirements customers and solar DG customers who have different demand profiles and load factors.
3. Banking adds to the subsidy that result under current rates and a cost study that reflects cost causation.
4. Rate design must be unbundled so that each utility service is priced separately (the ACC has made a good start on unbundled rates by identifying delivery services and power supply charges but more needs to be done in particular removing all fuel and variable generating costs from base rates and recovering those costs on a time of use

basis) and the rate design must be a multi-part rate to meet the principles of cost causation and matching.

5. Solar DG customers should produce at least the residential average return and rates for partial requirements, solar DG customers should be designed to produce the solar class return equal to the residential average from the final decision in this case.

Q. Which cost methodology should be used in future rate cases to promote equitable rates to consumers?

A. Solar DG residential customers have very different usage characteristics as compared to full requirements residential customers. That is the two groups are not homogeneous and thus need to be treated as separate classes in the cost study. Going forward, the solar residential customers should have rates based on the costs they cause. They should also have separate load research for both load and generation to precisely measure the system impacts of both delivery and production. The minimum system method for classifying distribution customer costs should be used to properly reflect costs caused by customers regardless of load. Setting rates based on costs also means that it is important to send these customers a price signal that creates value for smart inverters. Thus, the demand charges for these customers should be based on kVa rather than kW.

VI. <u>Separate Rate Treatment for DG Customers.</u>

Q. What is the rationale for treating partial requirements customers in a separate class from full requirements customers?

A. Under two-part rates the assumption that is required for rates to reflect cost causation is that load characteristics are relatively homogeneous as to cost causation and to load patterns. Relative homogeneity existed when kWh rates were first used for residential

customers in the late 19th century because the only electric load was lighting. The demand was a function of the number of fixtures and kWh consumption was a function of average operating hours. Thus a simple two-part rate with a customer or access charge and a flat kWh charge represented a reasonable rate because the cause of cost and the load characteristics of residential customers were the same. Over time, the end use load profiles of residential customers has changed and electric rates evolved to reflect different load characteristics through declining block rates to reflect higher load factors for larger customers and through separate rate classes for different end-use residential loads such as all electric rates or special provisions for specific end-uses such as a water heating block for customers with electric water heating. The trend away from these rate provisions to flat and inverted rate designs and fewer special provisions made rates less cost based as end-use load profiles continued to be more diverse because larger groups of customers were served under rates that were simple but not capable of reflecting the costs caused by less homogeneous subgroups within the class. With the addition of partial requirements customers within a class, customers are no longer homogeneous as the following table illustrates by comparing two identical premises with the same demographic characteristics:

Table 6 Comparison of Full and Partial Requirements Customers

Measures	Full Requirements	Partial Requirements
Customer Maximum Demand	10 kW	10 kW
Annual Energy Consumption	35,040 kWh	35,040 kWh
Annual Billed kWh	35,040 kWh	853 kWh*
Billing Load Factor	40 %	1 %

* Based on 35,040 kWh less the energy produced by a 19 kW Solar PV system operating at a 20.54% annual capacity factor.

From a cost perspective the delivery cost is the same for these two customers. The difference in cost recovery under the current TEP Electric rates is calculated in Table 7 below based on the current full TEP rate.

Table 7 shows that the annual subsidy under current rates is almost $194 per kW of installed solar capacity in this example. This subsidy is based on equal treatment for equal cost causing delivery characteristics and is not tied directly to a measure of the cost subsidy which may be even larger as a result of the higher delivery demand requiring more distribution capacity. On the basis of cost causation there will be subsidy in the generation and transmission portion of the rate simply because the solar PV capacity of 19 kW will not be coincident with the system peak demand.

Table 7 Customer Revenue under Rate Res-01

Billing Determinants	Local Delivery	Full Requirements	Partial Requirements
Customer	12	$120.00	$120.00
0-500 kWh			
Full Requirements	6000	$535.34	
Partial Requirements	853		$77.89
501-1000 kWh	6000	$594.34	
1001-3500 kWh	19548	$2,201.16	
Over 3500	3492	$430.60	
Total Bill		$3,881.44	$197.89
Difference		$3,683.55	
Subsidy Per kW			$193.87
Notes	Assumes saturation of first two blocks in all months		Assumes 853 kWh in summer only
	Assumes 11,000 kWh in summer in third block		

Both Tables 6 and 7 are illustrative of comparing two individual customers- a full requirements customer and a partial requirements solar DG customer. The results of this comparison are consistent with and support the class conclusions in the cost studies.

It should be noted that this result occurs because of the current price signal based on energy that incents the customer to install a system that maximizes energy production without regard to the capacity value of the solar facility[37]. This means that solar panels would face south in the Northern Hemisphere to maximize energy production instead of west to maximize summer peaking capacity contribution.[38] In that event the capacity contribution of solar and the later timing of the solar customers class NCP would result in no distribution cost savings and potentially even higher distribution costs associated with the class NCP for DG customers occurring at a later hour. Under the most favorable circumstances a 5 kW solar facility would reduce the class NCP by about 0.5 kW and that would not be enough to result in smaller distribution facilities such as a transformer or conductor even if all of the customers using the same equipment had installed solar DG.

There is also the issue of a potential subsidy under the energy cost component of the base rate. That subsidy would result from the load pattern of the solar power delivery that does not occur in uniform high cost hours. In fact, solar output is maximized in hours outside the peak period as defined in the residential TOU rate in both the winter and the summer. Since the winter off-peak period represents the majority of operating hours in that season and represents only 33% of the summer peak operating hours it is reasonable to conclude that the solar energy value is less that the base energy charge.

[37] A generation and transmission on-peak demand charge would provide an incentive to consider both the capacity and the energy value when installing solar and also for investments in EE.

[38] See for example "9% of solar homes are doing something utilities love. Will others follow?", OPOWER Blog December 1, 2014.

Q. Is there other evidence that the solar DG customers require their own rate class?

A. Yes. It is instructive to compare the distribution of bills for solar DG customers after installing solar DG to the counterfactual loads before DG. Figure 4 below shows how the bill frequency has changed dramatically from the full requirements monthly kWh billing to the solar DG monthly kWh billing.

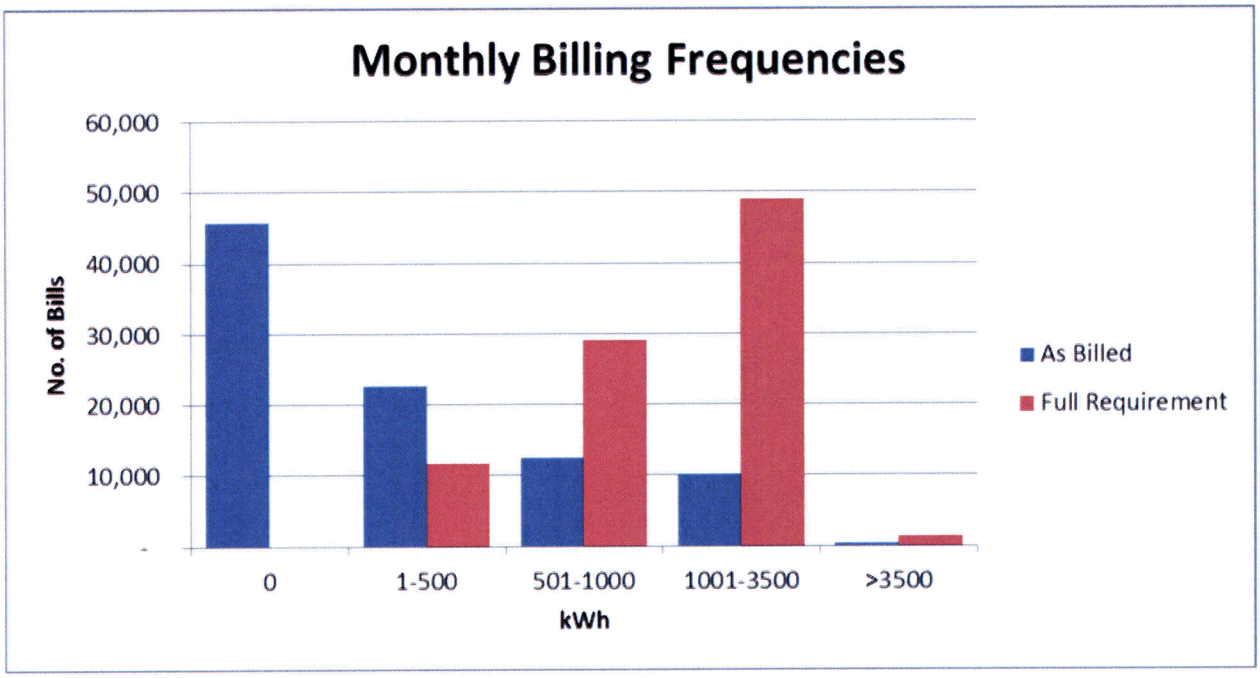

Figure 4 Monthly Billing Frequencies

This figure shows that these customers had more bills in the third tier of the rate as full requirements customers than in any other tier of the rate and these customers had no zero bills as one would expect. This group of customers with DG now has almost the same number of zero bills as they had third tier bills when they were full requirements customers. Given that there delivery cost based revenue requirements have increased there is no way a kWh rate could ever recover these costs equitably from DG customers.

Q. Please summarize why a residential DG customer needs its own rate class.

A. All of this evidence suggests that with a two part rate and net metering with banking can never result in just and reasonable rates for partial requirement DG customers. The only possible alternative to treat partial requirements, DG customers equitably is a separate rate class with a three-part rate. Further, the excess kWhs should not be banked but should be purchased at a market based rate. This solution, as proposed by TEP, is practical immediately and need not wait until there is a general rate redesign for all residential customers. It also illustrates that there is a substantial subsidy inherent in net metering because the use of self-generated kWhs saves the DG customer more than the system saves by an amount that over-values the DG contribution. This is part of the reason that commissions and others are developing Value of Solar (VOS) and a buy all sell all rate as a substitute for net metering.

Q. Please discuss net metering.

A. From an economic perspective solar DG is not a least cost solution for the utility and its customers when community solar and utility scale solar have much lower installed capacity costs because of economies of scale. Furthermore, I disagree with any of the critics of this approach that may suggest that eliminating the banking feature is in effect violating the concept of "netting" which is fundamental to the net metering concept. The fact that the Company is simply crediting back energy produced by DG at a market value different from the total delivered cost of power to the customer does not change the net metering that the customer sees relative to its own use of energy but may change the value of that netting feature as it should to avoid undue discrimination. There are valid cost based reasons including the provision under PURPA that makes adoption of any standard including net metering satisfy the principle of equitable rate treatment for customers.

Q. Are there other issues that make the separate treatment of DG customers necessary in the current proceeding?

A. Yes. The unequal treatment of customers who have the same costs but provide very different levels of revenue to recover those costs is a perfect demonstration of undue discrimination and that the current rates are no longer just and reasonable as the result of a combination of the net metering provisions and the current inverted block two-part rate with a low monthly basic customer charge. Essentially, the recovery of almost all of the fixed cost of service in volumetric charges results in undue discrimination when the customers in a class are no longer homogeneous. Staff witness Solganick reached the same conclusion and states "two customers who require the same equipment might use very different amounts of energy and again would result in one customer being undercharged and the other overcharged."[39] Witness Solganick also notes that "Residential customers are increasingly becoming non-homogenous as they adopt various forms of heat and distributed generation and as their lifestyles, demographics, and work patterns become increasingly more diverse."[40] When the difference in the annual bill of a full requirements customer and a partial requirements customer with identical peak demands is 19 times a partial requirements customer's total bill the subsidy is no longer just and reasonable and constitutes undue discrimination. The only practical solution is to eliminate the net metering provision and recover costs under a separate rate schedule for partial requirements customers as proposed by TEP. Further, it is imperative to immediately flatten the four tiered energy rate to two tiers as proposed by the Company to send a better price signal to other potential DG customers. This is a necessary step as TEP moves over time to TOU based fuel charges and demand based charges for fixed costs. This solution to just, reasonable and non-discriminatory rates has been recognized as the ideal rate since 1900 but could not be implemented because of metering technology

[39] Direct Rate Design Testimony of Howard Solganick ("Solganick Rate"), page 6
[40] Ibid. page 9

and costs. Those two constraints no longer apply and reasonable rates can be achieved by the appropriate transition plan.

Q. Is the TEP proposal of a three part rate for new DG and ultimately for all customers consistent with current views on best practices?

A. Yes. In recent years, many industry observers have supported multi-part rates as the best practices approach to designing rates for DG as noted by a number of organizations such as e-Labs of the Rocky Mountain Institute who states "These technologies can provide to or require from the grid energy, capacity, and ancillary services based on individual capabilities. But these characteristics vary along many dimensions that are not reflected in block, volumetric rates. For example, when a customer is exposed to a high marginal price tier in an inclining block rate structure, rates can both reinforce and skew the message that price signals should send. Rooftop PV can look more competitive with retail rates based on the higher credit received for energy production."[41] This is the exact conclusion reached above relative to the inefficient orientation of solar panels relative to actual avoided costs because of the energy only price signal.

A report from the MIT Center for Energy and Environmental Policy Research states the following:

> Allocating network costs primarily on the basis of volumetric energy consumption presents *inefficiencies in distribution systems* evolving to incorporate a growing number of DER and a growing list of new stakeholders. These inefficiencies include: *few price signals to incentivize optimal network utilization; cross-*

[41] "RATE DESIGN FOR THE DISTRIBUTION EDGE: ELECTRICITY PRICING FOR A DISTRIBUTED RESOURCE FUTURE", e-Lab Rocky Mountain Institute, August 2014, p.15 http://www.rmi.org/elab_rate_design

subsidization among network users; and business model arbitrage of rate structures.[42] (Emphasis added.)

That same report supports the use of a customer component of the distribution system and demand charges for customers based on the capacity component of the system.[43]

In a report prepared for EEI titled "Retail Cost Recovery and Rate Design" Kenneth Gordon (the former Chairman of both the Massachusetts Department of Public Utilities and the Maine Public Utilities Commission) and Wayne P. Olson make the following statement:

> To the greatest extent possible, customer- or demand-related fixed costs should not be rolled into energy charges. The end-use customer often sees too high a price for energy and too low a price for demand and customer charges. Hence, the customer never receives the economically efficient price signal for either one.[44]

Each of these references correctly recognizes the role of multi-part rates in addressing the issues of efficient pricing and reflecting cost causation. Current rate designs as recognized by TEP and the Staff correctly conclude that the current two-part rate for residential customers is inefficient and includes subsidies. The important point is that subsidies resulting from averaging costs in class rates are far different than artificial subsidies that reach the level of undue discrimination as they do in the case of net metering with largely volumetric rates. Average cost subsidies are found in items such as using the average service line costs knowing full well that the customer on the same side of the street as the transformer has a shorter service line than the neighbor across the street. Short of designing rates for each customer, a utility and its regulators must accept

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[42] "A Framework for Redesigning Distribution Network Use of System Charges Under High Penetration of Distributed Energy Resources: New Principles for New Problems" Ignacio Pérez-Arriaga and Ashwini Bharatkumar, October 2014, p.6 https://mitei.mit.edu/system/files/20141028_UOF_DNUoS-FrameworkPaper.pdf

[43] Ibid. p. 16-20

[44] "Retail Cost Recovery and Rate Design" Kenneth Gordon and Wayne P. Olson, Prepared for the Edison Electric Institute, December 2004, p. viii. See also p. 26. http://www.ksg.harvard.edu/hepg/Papers/Gordon.Olson.Retail.Cost.Recovery.pdf

some level of intra class subsidy; however, it is incumbent upon them to address undue subsidies and discrimination. The subsidies under net metering with two part rates create undue discrimination that needs to be addressed in the current case, not postponed and not to wait on implementation of a phased approach to multi-part rates that does little or nothing to address the problem for years to come.

Q. Please discuss the claim that separate rate treatment for DG is discriminatory.

A. This is a common claim made by solar advocates who want to maintain the extremely favorable treatment (and profitable marketing opportunity created by the current combination of net metering and largely kWh recovery of fixed costs) accorded to solar DG. This is a classic example of the rent-seeking identified by Alfred Kahn and discussed above. The best way address this claim is to analyze the meaning of discrimination in the context of regulation. The Merriam-Webster Dictionary defines discrimination as *the practice of unfairly treating a person or group of people differently from other people or groups of people and the ability to understand that one thing is different from another thing.* As applied to solar DG and discussed above customers who become partial requirements customers are clearly different from full requirements customers and in that sense the discrimination is not inconsistent with the basis for designing rates for homogeneous classes of service. While it may be inconvenient for the solar advocates to recognize that solar DG customers differ from full requirements customers the evidence shows that this is precisely the case.

The customers are different based on load characteristics and in terms of cost causation. The cost studies and the results of those studies demonstrate that the solar DG customers are different from the residential class as a whole and are receiving rate treatment that is far more favorable under the current rates than is equitable. The cost results fully demonstrate undue discrimination.

The question becomes: Does singling out these customers for different rate treatment result in those customers being treated unfairly? The simple answer is no. This answer is supported by a review of the evidence as it relates to cost causation and the contribution of these customers to that cost compared to other full requirements customers. This is an empirical question that requires nothing more than the basic analysis of whether the solar DG customers contribute the same revenues toward the costs they cause as other customers who have the same cost causation. Since, the only true avoided costs are related to the marginal energy cost and some potential avoided generation capacity costs at less than one cent per kWh based on the coincident peak demand of less than 24% of the rated capacity depending on the peak load hour. (For this conclusion, the concept of the "Duck Curve" has not been considered because it may well eliminate this avoided cost also.) It is the existence of this undue discrimination that solar advocates seek to maintain to their advantage.

Regulatory policy is not required and in fact is prohibited from picking winners and losers when discrimination becomes undue. The goal of efficient regulatory policy is to develop a system of rates and charges for customers so that as they choose between full requirements service and partial requirements service the utility and its other customers are indifferent between those choices. Such a standard requires that the customers who choose different aspects of utility service pay the full costs of the services they choose to use. It is unreasonable for a customer to use a kilowatt hour of electricity that costs six cents to produce and then pay for that kWh by selling the utility a kWh when the utility value of that kWh is three cents but this is what occurs under the net metering banking provision. It is unreasonable for a customer to use the same distribution services as another customer and pay over far less per year for that delivery service. This later point is also impacted by the fact that the solar DG customer may actually cost more to serve for the same delivery service based on increased day ahead planning reserve requirements

and regulation reserve requirements related to generation operation. DG customers also impact the distribution system relative to VAR requirements and reduced life for voltage regulation devices as examples of cost increases. It is reasonable to conclude that the differences between full and partial requirements customers using solar DG are real, empirically verified and thus not discriminatory. It is also reasonable to conclude that separate treatment is a reasonable step to eliminate discrimination between solar DG customers and full requirements customers.

VII. The Economic Rationale for Multi-Part Rates.

Q. What is a multi-part rate?

A. A multi-part rate is an unbundled rate schedule that prices different services at the cost of each service. The TEP proposed three-part rate is an example of a multi-part rate without full unbundling. Ideally, the rate would have seasonal TOU prices for energy and these prices would be the same for each rate schedule except for the adjusting the energy costs for losses at each voltage level of service. No fixed costs would be recovered in the energy charges as is the case today. As I have discussed above there is no rationale for recovery of fixed costs in kWh charges with the exception that the class of service is nearly perfectly homogeneous.

Q. Is TEP's proposed rate structure an ideal rate structure in this sense?

A. No. Under TEP's proposal, a significant amount of fixed costs are still recovered in variable per kWh charges. TEP's proposal can be characterized as a step in the right direction.

Q. Is a two-part TOU rate a substitute for the multi-part rate as some parties have argued?

A. No. Witness Kobor, for example argues that demand charges are a compromise based on an article by Jim Lazar.[45] The statement she cites does not comport with rate history or with the logic of demand charges. Caywood writing in 1956 states "Thus, compromise rates are necessary, with the result that *the demand charge is sometimes included in the energy charge*." (Emphasis added.) This is the exact opposite conclusion from the one cited by witness Kobor. Witness Garrett makes a similar argument that utilities have been content with kWh rates for most of the 20th century. The level of contentment stemmed largely from the inability to justify the much more costly metering to measure demand for small customers and not from any recognition that the kWh rate and in particular inverted block rates were more cost based. All along utility ratemaking has recognized the compromise and has sought to improve cost matching with declining block rates, all electric rates, special rates for electric water heating and so forth. As I have demonstrated above there is no kWh charge that can reflect cost causation and the matching principle in today's modern electric utility where loads even in a class like residential customers are no longer homogeneous. As I have explained, the residential solar DG customers use the system very differently than a typical residential customer. A system that recovers fixed costs from volumetric TOU kWh charges is simply not going fairly recover costs from these solar DG customers.

Q. What about the argument of various parties opposing demand charges that the charges are not cost based?

A. Witness Kobor, witness Baatz, witness Garrett and others oppose the use of demand charges because they are not cost based. Witness Garrett and witness Kobor rely heavily

[45] Kobor at p. 54

on the article "Use Great Caution in Design of Residential Demand Charges"[46] to support their conclusions. As the above cost studies illustrate the demand charges as proposed move the rates toward cost of service not away from costs. It should be clear that the end-goal of cost based rates cannot be achieved with a single demand charge because different demands cause different costs—but energy charges can never match demand costs when load factors within a class vary as much as the residential class load factors vary from solar DG load factors. The only cost-based, non-discriminatory solution is to approve the TEP proposal for separate rate class treatment and immediate demand charges in the solar class and eventually demand charges in all rate schedules.

Q. Witness Kobor uses a Table 3 in her testimony that she labels "Garfield and Lovejoy Criteria".[47] Please comment on that table.

A. Since witness Kobor does not cite to the original source (an error in and of itself) she may not realize that she has not cited the actual source of the criteria. While the book by Garfield and Lovejoy does contain a listing of these criteria, Garfield and Lovejoy are not the original source. The original source is Dr. Henry Herz in an article "Impact of Cost Allocation on Gas Pricing," appearing in 58 Public Utilities Fortnightly 685, 692—694 (1956). Second, the Garfield and Lovejoy book makes two statements related to these criteria. "*Standards for testing the reasonableness of methods of allocating demand costs* have been developed by Dr. Henry Herz, consulting economist. These standards are *intended to apply generally, rather than to any one of the public utility industries*. Dr. Herz would judge the reasonableness of an *allocation method* in terms of its capacity to meet the following principles…"[48] (Emphasis added.) These standards are not specific to anything more than the allocation of demand costs in a cost study and they are general and thereby

[46] "Use Great Caution in Design of Residential Demand Charges", Jim Lazar, Natural Gas & Electricity, at 15 (Feb. 2016), available at https://www.raponline.org/document/download/id/7844.
[47] Kobor, p. 57
[48] Garfield and Lovejoy p. 163

cannot address the different capacity cost allocations required in an electric cost of service study. Decidedly, these are not criteria for evaluating rate design as used by witness Kobor. In fact, these standards have nothing to do with rate design and the comments on whether a rate design satisfies these standards do not appear in Garfield and Lovejoy at all. Rather the rate design evaluations are from the Lazar article not the author of the criteria or the authors of the text. The logic of imposing demand cost allocation methods on rate designs does not permit any conclusion about how well a rate design meets these cost allocation criteria because the allocation is only for capacity costs. For example, as noted above, if a class is nearly homogeneous any rate design based on the cost of service study that meets the criteria for capacity cost allocation would also meet the criteria for rate design. For example, the criteria that "The longer the period of time that customers pre-empt the use of capacity, the more they should pay for the use of that capacity" when demand costs are allocated on AED as in the case of TEP higher load factor classes will be allocated more demand costs and as long as the demand charges recover the demand costs the rate design will meet this criterion. If the rate is an energy only rate, the higher load factor customers in the class will pay a disproportionate share of the fixed costs. As a result any energy only rate TOU or tiered cannot meet the requirements of these criteria.

I will not address the cost of service issues associated with these criteria as they do not even recognize that there are different measures of capacity cost causation including CP, class NCP and customer NCP. As for cost causation, the hour's use of capacity does not change the peak responsibility for that cost (the lowest cost capacity available to meet that peak load) and any extra capacity costs as the result of more use may be included in an off-peak demand charge for production capacity. For local delivery capacity the cost is based on the customer's use in the highest billing interval of the year or the contract demand whichever is greater. If the customer operates at a 100% load factor or a 1% load factor the customer only pays for that cost with a maximum demand charge and a 100% ratchet. A

time of use energy only rate would meet that requirement if this was the only customer in the class. If there were three other 100% load factor customers but all with different demands the largest demand customer would pay the most for demand even if the actual costs were lower per unit of capacity because of economies of scale. The whole analysis of demand charges and of TOU energy charges is flawed and not reflective of actual results. In fact, any two-part TOU rate essentially consists of a customer charge and energy charges that are differentiated by peak and off-peak periods which may also be seasonally differentiated. This rate means that all fixed costs above those recovered in the customer charge continue to be recovered in kWh charges. It makes the implicit assumptions that patterns of energy consumption correspond with the various demands on capacity and load characteristics are sufficiently homogeneous that such a rate will fairly recover the various demand related costs. Further, energy costs are the most elastic component and recovery of fixed costs in the energy charge cannot ever match costs and revenues for individual customers or even for classes of customers because it is not energy that causes the fixed costs. Rather, it is various measures of demand that cause those fixed costs.

Q. Does the book by Garfield and Lovejoy discuss criteria for electric utility capacity cost allocation? Please explain.

A. Yes. The following page in the text provides "A set of standards for use in selecting a *demand-cost allocation method* for electric utilities has been set forth by a committee of the National Association of Railroad and Utilities Commissioners. Those standards are reviewed below:

1. The method should be based on some basic philosophy.
2. The method should be judged on its recognition of the following three factors: (a) demand in kilowatts; (b) use in kilowatt-hours; and (c) time of use of energy.
3. The method should recognize the characteristics of various loads.

4. The method should result in a relatively stable cost assignment which would not change radically with a shift in loads.
5. The method should require a minimum of measurements before and after allocation.
6. The method should permit allocation to a load which is completely under utility control, such as off-peak water heating.
7. The method should permit an estimate of the capacity cost that would be assigned to prospective loads.
8. The method should establish a minimum demand-cost allocation to off-peak customers.
9. The method should not be dependent upon judgments introduced in the allocation process."[49]

The TEP cost allocation meets these criteria. In either case these criteria apply to cost allocation not rate design and provide no basis for evaluating the rate designs proposed by TEP because they are silent about customer charges which Garfield and Lovejoy define as "The total of customer costs varies directly with the number of customers served. Customer costs include the expenses of meter reading, billing, collecting, and accounting. Also included are the expenses associated with the capital investment in metering equipment, customers' service connections, and *part of the investment in the general distribution system.* If administrative and general expenses are spread on the basis of investment, part of that expense total may be included in customer costs."[50] (Emphasis added.) Further, as I have demonstrated it is impossible for an energy only rate to match cost recovery of fixed costs in the current market environment.

[49] Garfield and Lovejoy, p. 164
[50] Garfield and Lovejoy p. 158

VIII. The Concepts of Fairness, Efficiency and Gradualism.

Q. A number of witnesses turn to Bonbright's principles as the basis for supporting their preferred rates. Please discuss Bonbright's principles in light of the TEP proposed rates.

A. Bonbright discusses ten principles of rate design that he identifies in three sub-headings of: Revenue-related Attributes; Cost-related Attributes; and Practical-related attributes. Of these ten principles Bonbright himself finds that these ten are "unqualified to serve as a base on which to build these principles because of their ambiguities ..., their overlapping character, their inconsistencies and their failure to offer any basis for establishing priorities in the event of conflict."[51] Bonbright then reduces his list to three criteria as follows: Criterion 1 – Capital Attraction; Criterion 2 – Consumer Rationing; and Criterion 3 – Fairness to Ratepayers[52]. After a discussion of these three principles, Bonbright discusses cost of service as a basic standard and states "Without a doubt the most widely accepted measure of reasonable public utility rates and rate relationships is cost of service."[53] Bonbright does not conclude that that cost of service can be implemented without complications and those complications are addressed in the text. These objections range from theoretical to practical. In part, some objections relate to limitations on technology that existed at the time Bonbright, et. al. wrote the book. Others fail to recognize that rate design and cost of service require a level of pragmatism that is based on the informed judgement of those most familiar with the utility and its customers. Where parties promote their individual interests (rent-seeking) and regulators are charged with balancing those interests while still dealing with the elements of the regulatory compact, inevitable conflict arises. Net metering is an example of the balancing of interests that "may have been a

[51] Bonbright, op. cit. p. 384
[52] Ibid. p. 385
[53] Ibid. p. 389

convenient benign fiction back when solar PV barely existed."[54] Yet now, rent-seeking seeks to perpetuate a rate design that no reasonable utility or even parties without a vested interest should be able to see as enriching solar interests at the expense of more costly options for consumers and loss of social welfare. Net metering does not meet any of Bonbright's three criteria for ratemaking and actively works against all three.

Q. Turning to Bonbright's first principle, Capital Attraction, how does net metering work against capital attraction when it is promoting private investment in rooftop solar DG?

A. New net metering has the impact of directly reducing the earnings of the utility by every dollar saved by new net metering customers between rate cases not recovered in the LFCR and the solar advocates as well as others oppose the LFCR actually recovering all of the lost fixed costs as proposed by the Company. Earnings below the allowed return make it more difficult for the utility to attract capital and increase the risk for investors as net metering increases rates for customers overall since the cost of rooftop solar is much higher than larger scale installations that produce the same renewable power benefits at a lower cost. Sound utility regulation would not allow this type of investment in a utilities rate base because it does not represent the least cost capacity option or the ability of a utility to lock-in a levelized energy cost for a utility plant. Under a least cost plan, rooftop solar would not be an option for efficient, least-cost RPS energy.

Q. As to Bonbright's second principle, how does net metering work against consumer rationing?

A. Consumer rationing means that approved rates should discourage wasteful use of utility services and promote all use that is economically justified through application of

[54] Blog Post at Energy Institute at Hass Energy "Billing Tweaks Don't Make Net Metering Good Policy" Posted on January 4, 2016 by Severin Borenstein

economically sound rate designs. Net metering is promoted by charging marginal prices that far exceed marginal cost and in purchasing excess energy at far higher rates than costs avoided by that energy. That impact promotes investment in solar DG facilities that are not cost effective absent that subsidy. As a result customers choose an option that is not economically efficient and make investments that result in wasteful use of the delivery system and investments to accommodate solar DG on the grid and with a new mix of capacity to meet the intermittent nature of the generation and the absence of any diversity in output. The resulting cost shifts from net metering raise non-participants rates even further above marginal cost and prevent the optimum use of utility facilities.

Q. As to Bonbright's third principle, how does net metering work against fairness to consumers?

A. The simplest impact of net metering is the level of undue discrimination between DG and non-DG customers who cause the same costs. Undue discrimination is an anathema to fairness among consumers to such an extent that it is typically singled out as a requirement for rates that must not occur for rates to be just and reasonable. Based on the results of the cost studies above and the examples of rate comparisons there is no question that net metering results in rates that are not fair, just or reasonable. This level of subsidy is far greater than the inevitable class subsidies resulting from averaging costs with in a class as I have shown by comparing solar DG in the counterfactual study to solar DG as a separate class of service.

Q. Why is gradualism an issue in this case?

A. TEP has proposed a gradual process to address issues with net metering. They have done so by proposing grandfathering of existing DG customers and only changing the payment made to cashout excess generation. Even that proposed payment is above the avoided cost

that an as available QF is entitled to for payment. This is recognition on the part of TEP that gradualism for rectifying net metering is an important first step. Gradualism is also reflected in the proposal to not eliminate the tiers in the inverted rates but to reduce the rate tiers to two and increase the customer charge as the first step toward rationalization of residential rates. TEP has also chosen to not propose the multi-part rate for non-DG customers that is so necessary for equitable rates and the matching principle, choosing instead to move gradually for non-DG customers on two-part rates.

IX. Serving All Customers in a Class under the Same Rate Schedule.

Q. Why should TEP rates serve residential customers under the same rate schedule?

A. This is an important question given the proliferation of rates that are available for residential customers. TEP rates are likely to be far more confusing as they stand today with different marginal cost blocks for different customers and different marginal costs for the same customer based on seasons and blocks plus the added confusion of optional rates. Simplifying the number of tiers and eliminating all of the special rates will make rates more understandable for customers even if they include demand charges. Current rates include TOU features that are based on different on-peak hours and have different price signals for those different hours. From a cost perspective, there is only one set of hours that represent the peak period and those hours are not based on load for a class or even load for the system. Basing TOU rates on seasonal and diurnal costs is fundamental to having effective and efficient TOU rates. All TOU customers should face the same price signals adjusted for losses associated with delivery. If a customer has load in an hour that load causes the costs in that hour the same as every other customer taking service in that hour. The purpose of rate design is not to cause changes in the customers' use of service. Rather, the purpose is to send a price signal as to the cost of that service so the customer can make

a decision that it values service at that time more or less than the cost. Customers who value that service more than the price will continue using the service. Customers who value the service less will not use the service either as a result of DER or EE or by shifting that use to a period where the value of the service is more than the price. Failure to send good price signals distorts the customers' choices and results in inefficient customer decisions. Good price signals must include maximum demand charges, peak demand charges, customer charges and TOU cost based energy charges. Rates will not be as simple as the compromise rates used today but they will be actionable by all customers even if the action is inaction.

Q. What do you conclude about the opposition to the TEP rate simplification proposals?

A. Witness Radigan opposes the simplification but that opposition is misplaced. Simplifying rates is part of the first step to having a single rate for all full requirements residential customers. Instead of making the transition more gradual and less costly, it is incumbent on all parties who have an interest to help smooth the transition not attempt to block a move that is ultimately in the interest of all consumers. In that regard, witness Zwick at least suggests an alternative to the current Lifeline morass of rates and special conditions. It makes no since to serve 20 customers on a specific rate that is not cost based but still may be ineffective in addressing the particular needs of the customers served.

X. <u>Customer Response to More Complex Price Signals.</u>

Q. Are customers able to respond to more complex price signals?

A. Yes. In terms of complex price signals the proposals in this case are comparable to rates in other parts of the world. For many years electric utilities have had more complex rate schedules for customers. The first marginal cost based TOU rates were introduced for large

customers in the 1950s. It is common to see separate supply and delivery charges with supply charges consisting of multiple blocks or TOU periods. Some rates have a customer charge that is tied to the maximum capacity that can be served by the utility. Under this arrangement the maximum delivery capacity is limited. This is a rate equivalent to a customer charge and a demand rate. In Italy, residential demand rates have been used for many years. Italy is an example of a demand charge that is based on maximum delivery capacity.

Australia is addressing the issue of residential demand charges to address both the issue of cost recovery for solar DG and added loads from air-conditioning in the residential class. The important point is that there is broad recognition of demand charges as a means to fairly recover distribution related costs based on maximum customer demand whenever it occurs. Production and transmission demand charges are partially related to system peak hours as discussed above.

Q. Are demand charges being adopted in the United States?

A. Yes. Municipal and cooperative utilities have adopted demand charge rates. In Florida where the Commission approves municipal rates Lakeland Electric has adopted a demand rate applicable to new solar DG customers and after 2025 for all solar DG customers. Cobb EMC in Georgia has adopted a demand rate for all new residential customers and the rate is mandatory for solar DG customers. Butler Rural Electric Cooperative has had a demand rate applicable to all residential customers since 2009. Customers adapt to rate schedules in different ways but they do adapt.

Q. Is there empirical evidence that customers do not respond to marginal price signals as much as to the total bill?

A. Yes. In a 2012 paper by Koichiro Ito of Stanford University found that customers respond to the total bill rather than marginal energy prices. This means that the non-linear energy prices under the inverted block rates are not useful as a tool to promote energy conservation. This is further evidence that the insistence of RUCO and others related to the tier consolidation of the TEP inverted rates does not promote conservation and the introduction of more efficient demand rates will not only promote just and reasonable rates, eliminate undue discrimination but will also be consistent with conservation. The findings in this article are not new and have been replicated over the years in various studies. This is further evidence that there is no requirement that residential customers fully understand the individual components of the rates to promote sound decisions related to a more complex rate design.

XI. Miscellaneous Issues.

Q. Witness Higgins states that TEP does not use the correct peak for calculating the load factor weights in the AED/4CP cost study.[55] Please comment on this issue.

A. In the traditional AED allocation system excess is based on a single peak and that peak is indeed used to calculate the system load factor as it should be. When the peak measurement is altered to other than a single peak as it is in this case- 4CP, the load factor weight applied to the average demand component is calculated on the basis of the peak used to determine excess just as it is in the traditional AED with a single peak. Thus the statement that the method is AED/4CP means that 4CP is the peak for determining excess demand and the peak for determining the relative weights for average which is the 4CP

[55] Higgins Direct Testimony at p. 13

load factor and the excess demand which is 1 minus the 4CP load factor. I understand why witness Higgins prefers the single peak load factor because it results in a lower weight for the average component and reduces costs allocated to high load factor customers because of their higher average demand as a class. In any event TEP has calculated the AED/4CP methodology in a logically consistent manner.

Q. Witness Seibel of the Solon Corporation expresses frequent and serious concern over proposals that he concludes are retroactive ratemaking. Please comment.

A. There are no proposals in the TEP filing that result in retroactive ratemaking. Witness Siebel is confusing the concept of setting a new, prospective rate schedule- the TEP proposal for new solar DG customers- as retroactive ratemaking. Retroactive ratemaking would occur if TEP proposed and the Commission approved a rate that allowed TEP to go back in time and bill customers on a different rate than they were billed on historically and collect additional revenues from those customers for that historic period. In this case, customers taking service after a certain date will be placed on a different rate after rates are approved and will be billed on that rate prospectively. This would be the equivalent of a now frozen rate being eliminated and replace by a new rate for example. The new rate would be effective prospectively. It is also the same as a case where the Commission makes a new rate design mandatory for some existing class of customers that fundamentally changes the rate design. It is certainly the Commission's prerogative to change a rate design or to replace a frozen rate with a new rate and those actions are not retroactive. This type of change in rate design has occurred as result of the PURPA standards on declining block rates and time of use rates. In both cases, Commissions that adopted these standards switched customer to a new rate regardless of when they begin service on the rates that were replaced. In these cases there was often no grandfathering as

has been proposed in this case for solar DG customers who connected to the system before TEP gave notice of an upcoming proposed change in rates.

XII. Conclusions.

Q. Please summarize your conclusions and recommendations in this case.

A. I conclude that the minimum system for classifying distribution costs in accounts 364-368 as proposed by TEP is a necessary condition for reflecting cost causation on the TEP system. That conclusion is supported by rigorous econometric analysis, public utility accounting, the NARUC Manual, numerous academic and industry literature written by scholars and rate practitioners over more than 100 years and analysis of TEP's own data. The only option offered as an option to the minimum system does not result in an allocation of costs that reflects the real physical assets that underlie service to customers and thereby fails the test of cost causation. The Commission should affirm the use of the minimum system classification in the TEP cost study going forward.

Second, I conclude that increasing customer charges as proposed by TEP is solidly grounded in cost causation, economic efficiency and results in rates that are just and reasonable. The Commission should approve the TEP customer charges as filed even if they do not grant the full revenue requirement increase.

Third, I conclude that the rates resulting from net metering with banking are decidedly not just and reasonable and rise to the level of undue discrimination. The Commission has an obligation to cure undue discrimination and should adopt the TEP proposal for modifying net metering by placing customers on a separate rate schedule designed specifically for partial requirements customers including solar DG customers. The rate should be based on the treatment of solar DG customers as a separate class of customers in the TEP cost study.

I conclude that the elimination of the top tiers of the TEP rates is a necessary step to begin the transition to more cost-based and efficient rate designs that comply with the just and reasonable standard for rates. Just and reasonable rates require a multi-part rate with customer, demand and energy charges.

I conclude that the Lifeline rates should be consolidated as part of a plan to serve all full requirements residential customers under a single rate with customer demand and TOU energy charges.

I conclude that customers can and will respond to the more efficient rates and that response will vary broadly among customers based on their own choices designed to optimize their individual satisfaction and valuation of electric service.

Q. Does this complete your testimony?

A. Yes.

Appendix A

DR. H. EDWIN OVERCAST

Educational Background and Professional Experience

Dr. Overcast graduated cum laude from King College with a Bachelor of Arts Degree in Economics. He received the Doctor of Philosophy Degree in Economics from Virginia Polytechnic Institute and State University. His principal fields of study included Economic Theory, Public Finance and Industrial Organization, with supporting fields of study in Econometrics and Statistics. He has taught courses at both the graduate and undergraduate level in Microeconomic Theory, Managerial Economics and Public Finance. In addition, he has taught courses in Mathematical Economics, Economics of Regulation and Money and Banking. While a faculty member at East Tennessee State University, he was appointed to the Graduate Faculty and subsequently directed thesis programs for graduate students.

In 1975, he joined the Tennessee Valley Authority (TVA) as an Economist in the Distributor Marketing Branch. He held successively higher positions as an Economist in the Rate Research Section of the Rate Branch and was ultimately Supervisor of the Economic Staff of the Rate Branch.

In May of 1978, he joined Northeast Utilities as a Rate Economist in the Rate Research Department and was promoted to Manager of Rate Research in November 1979. In that position, he was responsible for the rate activities of each of the operating companies of Northeast Utilities: Western Massachusetts Electric Company, Holyoke

Water Power Company, Holyoke Power and Electric Company, The Connecticut Light and Power Company, and the Hartford Electric Light Company.

In March 1983, Dr. Overcast became Director of the Rates and Load Research Department of the Consumer Economics Division of Northeast Utilities. In this position, Dr. Overcast directed the planning of analyses and implementation of system-wide pricing and costs for regulated and unregulated products and services of Northeast Utilities. As part of that responsibility, Dr. Overcast represented the system companies before state and federal regulators, legislative bodies and other public and private forums on matters pertaining to rate and cost-of-service issues.

Dr. Overcast represented Northeast Utilities as a member of the Edison Electric Institute (E.E.I.) Rate Committee and the American Gas Association (A.G.A.) Rate Committee. While serving on those committees, he was the Rate Training Subcommittee Chairman of the A.G.A. Rate Committee. He has been an instructor on cost-of-service and federal regulatory issues for the E.E.I. Rate Fundamentals Course and the E.E.I. Advanced Rate Course. Dr. Overcast also represented Northeast Utilities as a member of the Load Research Committee of the Association of Edison Illuminating Companies.

In March 1989, he joined Atlanta Gas Light Company as Director - Rates and was promoted to Vice President - Rates in February 1994. In November 1994 he became Vice President - Corporate Planning and Rates and was subsequently elected Vice President - Strategy, Planning and Business Development for AGL Resources, Inc.,

the parent company of Atlanta Gas Light Company. His responsibilities in the various rate positions included: designing an administering the Company's tariffs, including rates, rules and regulations and terms of service. He represented the Company before regulatory commissions on rate and regulatory matters and oversaw the preparation of the Company's forecast of natural gas demand. He was responsible for planning activities relating to the regulated businesses of the Company. He developed strategy for both regulated and unregulated business units, monitored markets for new products and services and identified potential new business opportunities for the Company.

Dr. Overcast has previously testified in rate cases and other proceedings before the Connecticut Department of Public Utility Control, the Massachusetts Department of Public Utilities, the Georgia Public Service Commission, the Montana Public Service Commission, the Missouri Public Service Commission, the Kansas Corporation Commission, the Arkansas Public Service Commission, the Corporation Commission of Oklahoma, the Ohio Public Utilities Commission, the New York Public Service Commission, the New Jersey Board of Public Utilities, the Michigan Public Service Commission, the Public Service Commission of Maryland and the Tennessee Regulatory Authority and the Federal Energy Regulatory Commission. In Canada, he has testified before the Ontario Energy Board, the British Columbia Utilities Commission, the New Brunswick Energy and Utilities Board and the Alberta Energy and Utilities Board. He has also testified before the subcommittee on Energy and Power of the U.S. House of Representatives and various committees of the Georgia General

Assembly.

Dr. Overcast joined R. J. Rudden Associates, Inc. as Vice President in September 1999. R. J. Rudden Associates became a unit of Black and Veatch in January of 2005. At that time he became a Principal of the EMS Division, he is currently a Director of Black and Veatch Management Consulting, LLC.

Appendix B

SMART RATES FOR SMART UTILITIES

Creating a New Customer Paradigm with Enhanced Pricing of Utility Services

H. Edwin Overcast

BLACK & VEATCH
Building a world of difference.

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Introduction

The U.S. electric utility industry is in the midst of rapid technological change and a transformation of the customer service paradigm. Much of the debate surrounding the changing industry centers on the implementation of more sustainable practices, such as energy efficiency and distributed energy resources, and compliance with more stringent environmental regulations. Notably, the debates continue to focus on technological and operational solutions. However, developing a 21st century rate design, or Smart Rates, can help facilitate solutions to today's industry challenges and provide customers with better price signals to assess competitive service offerings.

Smart Rates recognize that utilities provide a variety of services to customers and that the costs of these services are not always caused by the amount of energy the customer consumes. From a rate design perspective, Smart Rates fully unbundle[1] each component of utility costs and bill those components on the appropriate customer billing determinants consistent with the concept of cost causation. The unbundling of costs changes virtually all of the current rate traditions because it no longer rolls all utility costs into a single kilowatt-hour (kWh) charge or single kilowatt (kW) charge as if those costs are caused only by the single measure of customer energy consumption. Cost unbundling is critical for accommodating competition from on-site generation and allowing customers to choose which services they need from the utility.

This paper sets forth the theory and practice of 21st century rate designs through full rate unbundling of utility services and provides a framework for "Smart Rates" that enable customers to purchase – and pay an equitable and supportable price for – the services they want and need, regardless of their energy consumption levels. Through the use of Smart Rates, a utility can send customers a proper price signal associated with each service and improve the efficiency of all its services to customers.

Many aspects of the electric utility industry have changed dramatically since its founding, yet rate structures have significantly lagged these advancements. In order to best represent today's electric services and meet the needs of today's electric consumers, modern rate designs are essential. Smart Rates enable customers to use electricity and electric services more efficiently and provide utilities with revenue stability that enable the offering of more responsive services to accommodate customers' specific demands.

[1] Rate unbundling in this context is simply pricing each utility provided service separately so that customers pay only for the services they use, rather than paying a single charge that includes all services and assumes that all customers within a class have homogenous service requirements.

The Challenge with Current Utility Rate Designs

Current utility rate designs have their foundation in rates developed in the 19th century. The most common rates in use today are based on the watt-hour meter and consist of a fixed customer charge and some form of volumetric charge per kWh. As a practical matter, the choice of rate designs for various customer classes has depended specifically on the cost of metering relative to the total cost of service to the customer. For larger customers, most utilities use one of the following rate forms, both developed in the 19th century, or a combination of the two forms:

- **Hopkinson Demand Rate:** The most common method of pricing electricity for customers served with demand meters, such as large industrial customers. The Hopkinson Demand Rate consists of an energy charge for total kWh consumption in addition to a demand charge based on the facility's maximum energy use during any short time period (quarter-hour, half-hour or one-hour) in the month.
- **Wright Hours Use of Demand:** This rate form is also used for demand metered customers and bills those customers using kWh charges for different levels of hours use of demand. The Wright Hours Use of Demand consists of a customer charge and kWh charge blocks based on the number of hours that the customer's maximum monthly demand is used. Hours use is calculated by dividing the monthly kWhs by the measured maximum demand. The price of energy declines as the hours use increases recognizing both the customer's increased load factor and the increasing use of off-peak energy.

Even today, not all electric service applications are metered and the rate design used for such services are the same flat rate service used by the industry when it first started delivering electric power to customers in the 1880s.

Unless the rate design reflects cost causation for the services provided, customers who elect to buy particular service components will not pay for all the services they consume. This creates market instabilities as the result of cross-subsidies embedded in the utility's rates. Such cross-subsidies cannot withstand today's market pressures and will result in skewed prices and service levels for all market participants.

UNDERSTANDING COST DRIVERS

As noted, modern regulatory requirements for demand-side management (DSM) and energy efficiency, as well as customer demands for distributed generation (DG), do not align with current utility rate structures. The reason for this is that current rate structures incorrectly assume that energy, or measured kWh use, causes the utility to incur nearly all costs except for the costs that are reflected in a modest customer charge. For larger customers, the use of both a demand component and an energy component assume that a single measure of kW demand coupled with a unit kWh charge cause all of the fixed costs of utility service. In reality, utility services and the costs associated with each are caused by fixed and variable cost drivers. Both the fixed and variable cost drivers differ for different cost components and for different seasonal and diurnal periods.

Fixed costs do not change with energy use but can vary as a result of other cost drivers, such as customers or demand. Because these costs are fixed, they do not change with any hourly pattern of

energy use, even though some time interval is used to measure demand (e.g., highest 15, 30 or 60 minutes). *Appendix A* provides a brief description of the determination of demand for billing capacity-related costs to customers. Examples of utility fixed costs include:

- The investment in the fleet of plants generating electric power.
- The integrated transmission network investment that moves power from generators to the distribution system.
- The distribution system that provides power to homes and businesses.

Variable costs, on the other hand, can vary by season of the year, time of use, and/or environmental conditions such as forced outages or partial unit deratings that change the marginal source of energy for a particular time period. Examples of variable costs include:

- Fuel and fuel handling costs.
- Purchased power.
- Volumetric charges from regional transmission organizations (RTOs) or independent system operators (ISOs).
- Chemical costs.
- Energy-related operations and maintenance costs.
- Other environmental costs.

A Utility's Cost Causative Factors

Whether fixed or variable, costs are generally caused by one or a combination of three general factors:

- **Customer:** In general, if a cost varies as a result of customer count, then this is a customer-caused cost and can include customer service expenses (e.g., billing and meter reading), and facilities or assets located on the customer premise, such as the meter and service line, and even portions of the distribution system that serve to connect customers to the grid.
- **Energy:** These are the costs that vary directly with the number of kWhs produced, with the cost of fuel being the largest component.
- **Demand:** Demand related costs are those costs caused by the largest load in kW imposed on various parts of the utility's transmission or distribution systems.

  NOTE: *The demand factor that causes costs differs for different types of cost elements. For example, some form of coincident demand is the cause of both utility production and transmission costs. This peak hour or other measure of demand drives the required capacity along with a level of reserves and it is this measure of demand that should be the basis for the charges to recover that unbundled cost.*

Understanding the nature of different utility costs, the types of costs, and what causes costs to be incurred enables utilities to use specific pricing mechanisms that align with cost factors (Table 1).

Table 1 - Unbundled Costs by Type and Causal Factors

COST FUNCTION	COST TYPE	CAUSAL FACTOR(S)	PRICING
Generation Plant	Fixed	Demand	kW Charge
Transmission Plant	Fixed	Demand	kW Charge
Distribution Plant	Fixed	Demand, Customers	kW Charge and Customer Charge
General Plant	Fixed	Demand, Customers	kW Charge and Customer Charge
Generation O&M	Fixed, Variable	Demand, Energy	kW Charge and kWh Charge
Transmission O&M	Fixed	Demand	kW Charge
Distribution O&M	Fixed	Demand, Customers	kW Charge and Customer Charge
Administrative & General costs	Fixed	Demand, Customers	kW Charge and Customer Charge

This table shows the appropriate type of charge to recover the categorized costs in order to match cost causation with pricing without a detailed specification of the particular charge.

UNDERSTANDING UTILITY SERVICES

Unbundling of rates requires an understanding of all services a utility provides, and the cost drivers for each service. Most stakeholders generally understand that a utility provides safe and reliable electric service to its customers. However, most characterize this service as simply providing the energy product, which is one reason why the kWh-based rate structure continues to prevail today. In reality, utilities provide numerous services, including:

- Generation service
- Transmission and distribution services
- Customer service
- A variety of services that provide safe and reliable operation of the electric system as well as the facilities that use the electricity behind the meter, such as voltage regulation, in-rush current for starting electric motors and other ancillary services.

Each of the listed major functions of the utility can provide multiple specific services for a variety of customers. Furthermore, each service also includes a quality of service component, generally defined as firm or non-firm. Firm quality means that the utility provides service continuously without interruption except those related to unavoidable system outages (e.g. outages caused by severe weather). Non-firm quality means that the customer has agreed with the utility to permit its service to be interrupted at times the utility chooses. Table 2 demonstrates the multiple services provided under the generation functional umbrella, and how those services have different patterns of cost based on the quality of service.

Table 2. Potential generation services

SERVICE	QUALITY
Full Requirements	Firm
Full Requirements	Non-Firm
Partial Requirements- Supplemental	Firm/ Non-Firm
Partial Requirements- Supplemental Baseload	Firm/ Non-Firm
Partial Requirements- Supplemental Peaking	Firm/ Non-Firm
Partial Requirements- Standby/Backup	Firm/ Non-Firm
Partial Requirements- Maintenance Service	Firm/ Non-Firm
Partial Requirements- Scheduled Maintenance Service	Firm/ Non-Firm
Partial Requirements- Unscheduled Maintenance Service	Firm/ Non-Firm
System Related Services- Black Start, Area Protection, Frequency, Transmission Support	Firm

As Table 2 illustrates, there are many potential services (the list is not intended to be comprehensive) provided by the generation assets. Each service has different cost characteristics as well as quality differences. The result is that rates for unbundled generation may differ based on the type of service required. A similar set of requirements relate to transmission and even to some distribution services, although the closer the service is to the customer the less costs and quality of service provided vary. For example, if the provision of energy is non-firm, that service does not change the cost of the distribution facilities for serving the customer because the utility must still be able to meet the customer's maximum requirements when there is no interruption of service.

MODERN CHALLENGES TO TRADITIONAL RATES

Net Metering Policies

The fallacy of applying 19th century rate structures to the types of 21st century electric utility services required by customers is made clear by the economic effects of DSM programs, and the growing adoption of DG assets (e.g., rooftop solar) among customers who seek the economic benefit net metering policies provide. While these customers are using less energy, and some may even be net-producers of energy, they are still using utility services. However, because current rate structures assume that the level of kWh consumed by the customer causes the utility's costs; discontinuities in billing and cost recovery among customers are created. According to the Edison Electric Institute (EEI):

While net metering policies vary by state, customers with rooftop solar or other distributed generation systems usually are credited at the full retail electricity rate for any electricity they sell to electric companies via the grid. The full retail electricity rate includes, not only the cost of power but also all of the fixed costs ... that makes the electric grid safe, reliable, and able to accommodate solar panels or other distributed generation systems. Through the credit, net-metered customers effectively are avoiding paying these costs for the grid.[2]

Net metering is the practice of allowing on-site generation to reduce the kWh portion of the residential customer's bill (netting generation against load) on a unit kWh generated basis. Recognizing that under a utility's traditional rate design the kWh charge for these customers recovers most of the fixed costs and the variable costs of energy on an average basis, the compensation for the customer's level of self-generation essentially assumes that all of the costs not recovered under net metering can be saved by the utility. That is simply not the case.

Consider, for example, the utility that peaks after sunset in every month of the year. Solar PV makes zero contribution to reducing the fixed costs for that utility. Importantly, the only cost savings are the avoided energy costs - and that would not even be valued at the utility's highest energy cost hours. In this case, net metering forces all non-solar PV customers to bear the costs of production, transmission and distribution capacity costs that are caused by the solar PV customer. While this is an extreme case to illustrate this deficiency in net metering, there are many utilities where the peak loads occur when solar PV is not generating its maximum output. This means that the avoided costs of the utility will not be as large as the credit provided under net metering, and that a cross subsidy will be created which allows solar PV customers to avoid paying for the fixed costs they cause the utility to incur.

Demand-Side Management Issues

With respect to DSM, issues similar to those under net metering arise when DSM programs save energy, but not capacity. A simple example illustrates this point:

A recreational facility owner invests in skylights to save energy during the day. The skylight salesman calculated his expected savings by dividing the total utility bill by the monthly kWh and providing a unit kWh savings. However, the facility was billed on a commercial rate that included a demand charge. Needless to say, the savings did not materialize because the facility's peak demand occurred at night due to its heavy lighting load. The skylights created no demand savings - only daytime energy savings. Based on the actual savings, the skylights were not economic and the owner made a poor decision to invest his limited capital on an inefficient solution to reduce energy-related costs.

By unbundling rates, the utility recovers all of its costs from each customer regardless of the amount of energy (kWh) used by the customer, or when the energy was used. Such a pricing structure will create rates that fairly portray the value of the service in the market and will eliminate the inherent

[2] "Straight Talk About Net Metering." Edison Electric Institute (http://www.eei.org/issuesandpolicy/generation/NetMetering/Documents/Straight%20Talk%20About%20Net%20Metering.pdf). September 2013.

intra-class cost subsidies in current utility rates, creating benefits for all segments of the energy industry.

21st Century Rate Design

A 21st century rate design fully unbundles each component of cost and bills those components to customers based on the appropriate billing determinants (customer, kW, kWh) consistent with cost causation. The unbundling of costs and the implementation of modern rate designs appropriately change virtually all of the current rate traditions perpetuated over the years. Different rate components are billed separately and each customer will only pay for the services they use. This section focuses on the components of an unbundled rate design.

Unbundled rates consist of the basic customer, demand and energy charges. Under full unbundling, these basic rate components are translated into:

- Customer charge
- Production demand charge
- Transmission demand charge
- Distribution demand charge
  - Distribution substation service
  - Distribution primary service
  - Secondary distribution demand
- Energy charge
  - Energy service at transmission voltage
  - Energy service at substation delivery
  - Energy service at primary delivery with and without transformation
  - Energy service at secondary voltage.

Obviously, not every utility will require all of these distinct charges based on their existing service arrangements and the customers' available service options. Further, there may well be subcomponents of various costs associated with services such as back-up, standby, maintenance and supplemental power as each relate to generation, transmission, distribution and energy services. In some markets, unbundled services, such as meter reading and billing, may not be provided by the utility. In that case, the customer charge component needs to reflect the exclusion of the costs of these services.

A customer's rates may also differ based on geographic segments of the utility's system because costs may differ at different load nodes (this consideration is particularly important for systems with wide geographic reach that include different load nodes and/or climatic considerations.)

UNBUNDLED RATE COMPONENTS

Derivation of the Customer Charge

The derivation of a fully unbundled rate design begins with the customer cost component. While customer costs will always be a subject of debate among a utility's stakeholders, the logic

supporting this concept is quite simple: If a cost varies based on customer count, then the cost is customer-related. This includes a utility's customer service functions and its assets located on the customer premise.

Another element of customer costs are those portions of the utility's minimum distribution system required to serve even the smallest customer. Minimum distribution system requirements include transformers, secondary conductors, poles and/or underground facilities.

To derive its fixed customer charge, a utility uses a detailed cost of service study that unbundles costs into various components. These unbundled costs form the basis for setting the rates for each component of service. For example, if the cost of service study calculates the customer component to be $300 per year, that amount would be the basis for a $25 per month customer charge. The annual cost derived from the utility's cost of service study would include the annualized cost to support the investment in a meter, service line, transformers, secondary conductors and poles, Operation & Maintenance (O&M) expenses related to the customer's plant, general plant, and any other assets required to provide the service, and customer service expenses (e.g., billing, meter reading, customer accounts and collections).

Derivation of the Production Demand Charge

Not all electric utilities will have production demand charges. This discussion focuses on the need for such charges for a vertically integrated utility. In that case, the production demand charge includes the fixed costs of generation and the transmission lines and related facilities that interconnect the utility's generation to its bulk transmission system. Ideally, these costs would be collected through two separate demand charges. This is the preferred rate structure because the typical electric utility experiences distinct differences between the marginal costs of production for serving peak loads compared to the costs for serving loads occurring other than during the peak period (i.e., base load production). At the same time, with the expected increase in the penetration of distributed energy resources (DER) on utility systems, this rate structure will properly value the benefits of DER to the customer based on the times when such self-generation actually is operating.

In general terms, the first demand charge (known as the Production Peak Demand Charge) recognizes the capacity costs associated with the utility's peak demand period, while the second demand charge recognizes the higher capacity costs of base load units that provide substantially lower energy costs. These costs are recovered based on the maximum demand in the peak demand period subject to a one hundred percent ratchet.

The carrying cost of the utility's least-cost production resource (nominally a gas turbine) and the associated transmission costs would be collected as a demand charge based on a demand measure during the highest load hours, where load is defined as: *The sum of customer load, forced outage load, scheduled outage load and generator deratings.*

This demand charge reflects the unbundled costs of required capacity with a level of reserves. The result is that certain charges may be incurred by the customer based on specific time periods that may differ from on-peak hours for energy, in general, and may differ for generation and transmission. For example, if the reserve requirements are calculated by an RTO or ISO based on a specific set of critical hours, those critical hours may be appropriate for determining the billable production demand associated with peaking facilities. If these hours are very short periods, such as

the maximum demand hour in the summer months of June, July and August, it is not feasible to know in advance when those peak hours may occur and the peak hours used to measure the hours when the demand charge is applied may change from year-to-year and month-to-month.

It is important to note that deriving the Production Peak Demand Charge based on a short demand period runs the risk of shifting load out of that period. In addition, this also creates risk for increasing load after the peak demand period, causing the peak to occur in different hours because shifting load out of a short period may reduce natural diversity. It is critical that the shifting peak concept be fully assessed because there is a possibility that the loss of natural diversity in loads may cause other capacity-related costs to increase - such as for the utility's distribution and transmission facilities.

By establishing a longer fixed period for deriving the Production Peak Demand Charge, the shifting demand peak creates no issue for creating a new production demand peak outside of the demand hours. This is done by taking advantage of the natural diversity that occurs between loads.

It is also critical to understand that the need for capacity is based on more than just the customer load on the utility's system. Simply, the total maximum load on the system is the sum of customer loads, scheduled outage loads, unscheduled outage loads and unit derating loads. The latter two components change for every time interval just like customer loads. In some cases, the seasonal derating is known in advance based on the generation technology or a condition such as lower water flows that occur naturally.

Other factors may also derate the capacity of a unit without forcing the unit out of service (e.g., tube leaks). Since these types of occurrences reduce available capacity, they must be treated as load for purposes of determining the peak hours that matter for cost causation purposes. It has been said that if load factor on the generation system increases beyond a certain point, it will be necessary to build reserves just to schedule maintenance activities. Thus, it is important to understand the full demand on generation resources for purposes of establishing the demand period for production. Shifting load to off-peak periods does not always result in the full expected savings and could with some technologies create a new peak period in the former off-peak hours.

The second demand charge (known as the Production Base Load Demand Charge) is designed to recover that portion of the utility's revenue requirement associated with production not recovered through the Production Peak Demand Charge. The value of this charge may be zero in some circumstances. Where there are additional costs, the Production Base Load Demand Charge will be based on the highest monthly demand outside the peak demand period, without any ratchet provision. Thus, customers who benefit from lower cost energy will contribute to the additional capacity costs that produce those savings.

In the alternative, where utilities operate in restructured markets, the Production Peak Demand Charge of RTO or ISO participants could be based on the capacity responsibility determined by the operational control entity. This charge would be subject to a 100 percent ratchet on an annual basis. The remainder of the capacity costs not covered by the Production Peak Demand Charge would be recovered in a second demand charge applicable to the highest monthly load occurring in the month, without a ratchet.

Derivation of the Transmission Demand Charge

For transmission, the analysis of peak loads need not be the same as for generation. On integrated utility systems, native load may be only one component of the peak load. Understanding how the system is loaded on an hourly basis is a necessary element for the determination of transmission system peak periods. It is possible that the demand allocation for the generation function will differ from the allocation that is appropriate for the transmission function. This is particularly true where transmission for others across the utility system results in higher loading at times other than the native load system peak.

Transmission system loading on integrated utility systems is not solely a function of customer load on the system because of congestion management and centralized dispatch. For example, if load flows across the individual utility system because of lower cost generation, a transmission system may be fully loaded many more hours than retail customers' own load alone would indicate. Determination of the expected loading may also change because of events unrelated to the transmission facility owner, such as unit forced outages, changes in relative fuel costs, must-run generation and other factors that alter grid dispatch. The result of these factors is to change the allocation and cost responsibility for transmission in a way that impacts the appropriate demand period determination. To do this, it is important to understand the components of the transmission system and the cost drivers for each:

- **Generation laterals**: costs driven by connecting generation to the system and should be included in the generation/production demand costs.
- **Load laterals:** Costs driven by the loads on the lateral and may differ from the system or the transmission peak. Costs for load laterals are recovered through the distribution facilities demand charge.
- **Bulk transmission system**: Costs driven by loading of the bulk system and are recovered based on the load characteristics of the system. Options include:
  - Maximum load occurs in each month of the year: The demand charge is based on the peak period demand within every month and is the basis for the transmission demand charge.
  - Maximum load occurs in summer: If system is loaded only during four summer months, then the costs would be based on demand that occurs during the peak demand time period, even though the charges are billed over all 12 months. In essence, the non-seasonal demand would be equal to the average of the four critical peak demand periods.

Derivation of the Distribution Demand Charge

Distribution demand costs are driven by the customer peak load whenever it occurs. These costs are not identifiable on a time-of-use basis and the individual customer's maximum demand or contract demand (the maximum obligation of the utility to provide the local distribution service) is the appropriate demand measure to use to recover such costs. Any distribution costs not recovered in the customer cost category and the portion of transmission costs for load laterals are recovered in the distribution demand charge. The distribution demand charge would include a 100 percent demand ratchet based on either the customer's contract or actual demand.

As a general rule, the distribution system components peak at times that may not be coincident with the generation or transmission peak load. In planning and designing the distribution system,

an important design element is natural load diversity that occurs based on the electricity use of the premise (businesses and residences have differing time patterns of load).

Certain activities, such as storage may alter the natural diversity of loads. For example, controlling electric water heaters by shutting them off for extended peak periods results in much higher coincident peak demands on delivery facilities because the natural load diversity is disrupted by the added control. The result is both higher distribution costs and higher peak demands for customers subject to control. Based on experience with time-of-use rates, there is potential for a similar impact on the distribution peaks and the cost of delivery service.

The recovery of distribution-related costs based on maximum demand whenever it occurs is fundamental to cost-based rates.

The three components of the distribution demand charge are recognized in the cost allocation process and relate to substation costs, primary facilities and secondary facilities not recovered in the customer charge. Conceptually, in a modern electric system all secondary costs should be customer-related. The allocation process recognizes that diversity increases as the load is measured further from the customer's individual load. To the extent that loads are homogeneous, a single distribution demand charge would be adequate. If there is little homogeneity, then the costs may need to be broken out separately but billed under the same 100 percent ratchet provision.

The customer and ratcheted demand charges would be based on an annual cost payable in 12 equal amounts. These annual charges would be premise-based so that a new customer occupying the premise would have his bills initially based on the premise's measures of demand. In addition, if a customer has service turned off at the premise and subsequently turns service back on, the customer would be responsible for the payment of fixed charges for the period where service was not taken as part of the cost of establishing service. Non-ratcheted demand charges would be based on the actual monthly use of demand.

Derivation of the Energy Charge

The final component of the unbundled rate design is the energy charge. The energy charge recovers all of the variable costs associated with the production or purchase of power. Further, the energy charge is not part of the utility's base rate. Rather, it is reflected in a full tracking fuel clause that recovers not only fuel and purchased power, but also variable production costs, environmental costs (e.g., scrubber chemicals), variable charges from the RTO or ISO, and any other costs that change with the consumption of energy.

The energy charge is subject to regular adjustments, like a fuel clause, and includes a deferral account that matches these costs dollar for dollar. The energy charges under this charge are differentiated based on cost causation by season, by time of use, by voltage level of service and, where applicable, by critical periods above and beyond the time of use periods. The adjustments to this charge are always seasonal-based adjustments in the sense that over or under recoveries of cost in a season are subsequently recovered in that season.

Energy charges may not require the inclusion of all of the cost components described above. For example, some utilities may not have distinct seasons. Others may have diurnal cost differences that

are so small that there is no reason to separately bill for those differences. Some utilities with little diurnal difference may instead have critical peak periods when, for a few hours per month or for a few hours per season, they may experience costs far in excess of typical average or marginal cost levels. For example, the average cost might be approximate $35 per MWh for 97 percent of the time, but could easily exceed $100 per MWh in the remaining hours. In this case, the ability to provide proper price signals to customers would be important as would rate provisions designed to match costs and revenues under the critical peak period.

ILLUSTRATIVE RATE STRUCTURES

Using the concept of fully unbundled rates means that a utility's traditional rate class definitions are no longer as important. Cost-based rates enable the use of a less homogeneous class of customers, (e.g., there is no need to have one or more residential classes of service). There will no longer be a need for separate rate classes for certain end-uses, such as churches or schools, to reflect their different load characteristics compared to those of other general service customers. The ability to recover costs based on individual load characteristics then allows for rates based on other relevant conditions of service that have specific cost implications, such as voltage level of service or transformer or substation ownership.

Thinking about the factors that impact cost must begin with the customer component of costs including meter and service investment. This classification should also recognize that voltage level of service is of particular importance. In that context, it is possible to define a Small General Service Secondary Voltage Class. This class would consist of all customers who have essentially the same types of meter installations and service lines (e.g., residential, residential space heating, small commercial, small commercial all electric, etc.). Differences in other characteristics of utility service, such as demand coincidence factors and individual maximum demands, would not matter since the costs that are caused by these demand measures are already unbundled. The important point is to derive each component of the rate structure to reflect the actual cost of service.

Other classes would include General Service Primary Voltage, General Service Primary Voltage Transformer Ownership, Large General Service Substation, Large General Service Transmission, Non-Firm Service Rates and Back-Up and Standby Service Rates. These rates would reflect the different costs associated with each service and, as appropriate, seasonal, time of use and critical peak pricing-type considerations based on service level requirements and associated costs.

Customers who require unique service arrangements would have those costs recovered in a separate monthly fixed charge for directly-assigned facilities. For example, an industrial customer may take service at the substation, but require one or more dedicated lines to connect the substation to its facility. In that instance, the dedicated lines would be a directly-assigned cost and recovered under a separate charge unrelated to the customer's actual load.

To illustrate these concepts, the following tables outline the rate forms for General Service Secondary Voltage Class and General Service Primary Voltage Class customers.

Rates for the General Service Secondary Voltage Class assume the following operating conditions:

- All customers have the same meter costs and the average cost of secondary service lines consistent with the applicable line extension policy (customer's requiring a greater level of service investment make an appropriate contribution for the excess investment).
- Customer costs include a minimum system component for local distribution facilities at the secondary level.
- All primary related costs are included in the distribution demand charge.
- The utility is strongly summer-peaking for the 4 months, June through September.
- Partial requirements customers take service under this rate and the applicable back-up and standby service rate.
- Customers who require unique service arrangements either make a contribution in aid of construction for excess facilities or they pay a separate fixed charge.

Table 3 - Rate structure for General Service Secondary Voltage Class customers (i.e., residential)

RATE STRUCTURE (Billed amount)	TYPE OF CHARGE	DESCRIPTION OF CHARGE
Customer Charge $300.00/year or $25.00/month	Fixed	Charges that support the customer service functions of a utility (e.g., billing, meter reading, distribution connection)
Distribution Demand Charge $3.00/kilowatt of billed demand	Fixed	Charges resulting from the demand-related portions of the distribution system. This charge can be based on the greater of the current month's maximum demand, or the maximum demand occurring in any of the preceding 11 months.
Transmission Demand Charge $12.00/kilowatt year or $1.00/month	Fixed	This charge is for services provided by the bulk transmission system. It should be based on the rolling average of the maximum on-peak demand for the system
Production Demand Charge $96.00/kilowatt year or $8.00/month	Fixed	Includes the fixed costs of generation and the infrastructure that connects generation to the bulk transmission system.
Energy Charge Charges would vary based on time of use, such as $0.058/kWh for summer on-peak and $0.038/kWh for winter off-peak	Variable	Recovers all of the variable costs associated with the production or purchase of power, most notably fuel and environmental costs.

Charges based on a hypothetical vertically integrated electric utility providing a bundled service.

The rate components of a General Service Primary Voltage Class are outlined below assuming the following operating conditions:

- All customers have the same meter costs and the average cost of secondary service lines consistent with the applicable line extension policy (customer's requiring a greater level of service investment make an appropriate contribution for the excess investment).
- Customer costs include a minimum system component for local distribution facilities at the primary level.

- Remaining primary related costs are included in the distribution demand charge.
- The utility is strongly summer-peaking for the 4 months, June through September.
- Partial requirements customers take service under this rate and the applicable back-up and standby service rate.
- Customers who require unique service arrangements either make a contribution in aid of construction for excess facilities or they pay a separate fixed charge.

Table 4 - Rate structure for General Service Primary Voltage Class

RATE STRUCTURE (Billed amount)	TYPE OF CHARGE	DESCRIPTION OF CHARGE
Annual Customer Charge $600.00/year or $50.00/month	Fixed	Charges that support the customer service functions of a utility (e.g., billing, meter reading, distribution connection)
Primary Distribution Facilities Demand Charge $24.00/year or $2.00/kilowatt of billed demand	Fixed	Charge based on the greater of the current month's maximum demand or the maximum demand occurring in any of the preceding 11 months payable in monthly installments.
Transmission System Demand Charge $11.75/kW-year or $0.98/month	Fixed	Charge based on the rolling average of the maximum on-peak demand occurring in the hours of 12 noon through 9 pm weekdays in the months of June through September payable in twelve monthly installments
Production Peak Demand Charge $94.00/kW-year or $7.84/month	Fixed	Charge based on the rolling average of the maximum peak demand occurring during the hours of 12 noon through 9 pm weekdays in the months of June through September payable in twelve monthly installments.
Production Base Load Demand Charge $6.86/kW per month	Fixed	Charge based on the actual maximum demand occurring monthly regardless of the time the demand occurred.
Energy Charges Variable	Variable	The energy charges hereunder shall be determined from time to time to recover the total variable costs associated with the production, purchase and delivery of energy to the Company's transmission system including any volumetric charges imposed under an RTO/ISO Tariff. The summer season is defined as the months of June through September. The charges effective for the twelve months commencing June 1, 2014 are as follows: • Summer On-Peak (Hours 10 AM to 11 PM weekdays excluding holidays) $0.568 per kWh • Summer Off-Peak (All other hours in the season) $0.0441 per kWh • Winter On-Peak (Hours 6 AM to 10 AM and 5 PM to 9 PM weekdays excluding holidays) $0.0451 per kWh • Winter Off-Peak (All other hours in the season) $0.0372 per kWh

As these two rate structures illustrate, many of the unit charges for primary customers are lower because generation and transmission capacity related costs reflect lower primary voltage losses. For primary distribution costs, the lower charge represents the exclusion of secondary facilities

from the cost of service at the distribution level. The lower energy-related charges are also the result of lower losses. The higher customer charge reflects higher metering and service costs, including using primary minimum system costs for service at this level. This general pattern will be repeated for each additional rate schedule with charges declining as the result of fewer facilities and lower losses. In addition, charges such as the residual generation costs or transmission costs will differ based on class load characteristics.

ROLE OF ADVANCED TECHNOLOGIES

Perhaps the primary reason rate structures have not changed significantly during the past century was due to a lack of technology to measure and appropriately charge for a variety of utility services. Until recently, utilities did not possess the technology and capability for measuring and recording data for each of its individual cost drivers.

Today's smart meters and advanced metering infrastructure (AMI) enable utilities to measure more than monthly kWh consumption. The technologies and back office software programs enable utilities to produce dynamic pricing information for customers and measure, record, bill and credit based on the usage levels of each service. Examples of additional services advanced technologies can track include:

- Time differentiated energy costs including critical peak prices;
- Demands by time of use and by maximum demand regardless of time; and
- Power factor measurement.

Smart meters permit a wider variety and type of price signals that can remove rate subsidies and send better, more cost-effective price signals to customers. With smart meters, each different rate component may be billed separately, enabling customers to pay for only the services they use.

OTHER CONSIDERATIONS

In addition to the various unbundled charges described above, it will be important to overlay seasonal and diurnal cost characteristics, critical peak pricing and time-of-use pricing, load control credits and other yet to be developed programs that reduce loads and create cost savings that would not be reflected in rates. Thus, we would expect to see energy prices that vary by season and by time of day based on time periods defined by cost differences, where appropriate. It will be important to develop seasonal and diurnal periods based on the underlying marginal costs recognizing that for some utilities those periods may vary in different parts of their systems. This would be the case where a portion of the utility delivery system is served off an electrically isolated load node of the transmission system. Where the system receives service from isolated facilities, the cost of these facilities and service should be borne only by the customers using these services. If the system is fully integrated, the costs of different nodes should be averaged across those nodes.

It is also important to remember that because unbundled rates eliminate intra-class subsidies that are included in many of today's traditional rate structures, certain policy goals could no longer be viably reflected as part of the rate. As such, programs such as low income bill assistance would need to be addressed indirectly through fixed bill credits funded by a separate rate component.

Ultimately these unbundled rates will be designed to recover the utility's class-related revenue requirements. The resulting price signals will be significantly more efficient from an economic

perspective resulting in less resource waste and more economically efficient power systems. A key element of the successful implementation of unbundled rates will be to educate customers on how the rates reflect the underlying costs of particular utility services and how the customer can manage electricity use to reduce those costs. Overall, such rates are expected to generate efficiency gains for both customers and the utility.

The benefits of unbundled Smart Rates will accrue to every stakeholder group even though some members will pay more for the services they buy and others will pay less. Customers who pay more benefit from receiving the correct price signal and understand the benefits of alternative choices related to DSM and DG investments. For the utility, unbundled rates will not change the utility's revenue requirement in total, but will impact the stability of revenues favorably and will cause the utility to be more proactive in its marketing of unbundled services to customers. It will likely take substantial effort on the part of the utility to educate stakeholders of these benefits in a rising cost environment. It is the Smart Rates that will allow customers to use electricity more efficiently and allow the utility to recover its costs from customers who cause those costs to be incurred. While the utility will be economically indifferent as rate designs change, it will also benefit from better price signals as consumers adapt to the cost causative factors that form the basis for unbundled rates. Changing rate design will also impact customers who have made investments based on the economic signals of the 19th Century rates and some of those investments will no longer be cost effective. The issue of customer stranded costs will be a difficult element of the transition, but is inevitable because of technological advances in metering and in utility operations.

The end result of unbundled rates will be a more cost effective and better integrated utility system to the benefit of economic growth and new investments that enhance the efficiency of the utility grid. This new customer paradigm is a prerequisite for improving the safety and reliability of the utility system.

Appendix A

As electric rates become unbundled, it is important to understand the concept of demand billing. The concept of demand billing is one of measuring the maximum capacity of the electric utility's system used in any particular period of measurement. Load varies from moment to moment based on the actual use of electric appliances including motor loads such as compressors in HVAC systems or refrigerators and freezers. Lighting load varies even from minute to minute as lights are turned on and off. Some loads run continuously while other loads operate infrequently. The net result is that any particular customer can have a different load shape on a daily basis.

Figure A-1 Daily Residential Hourly Load Shape

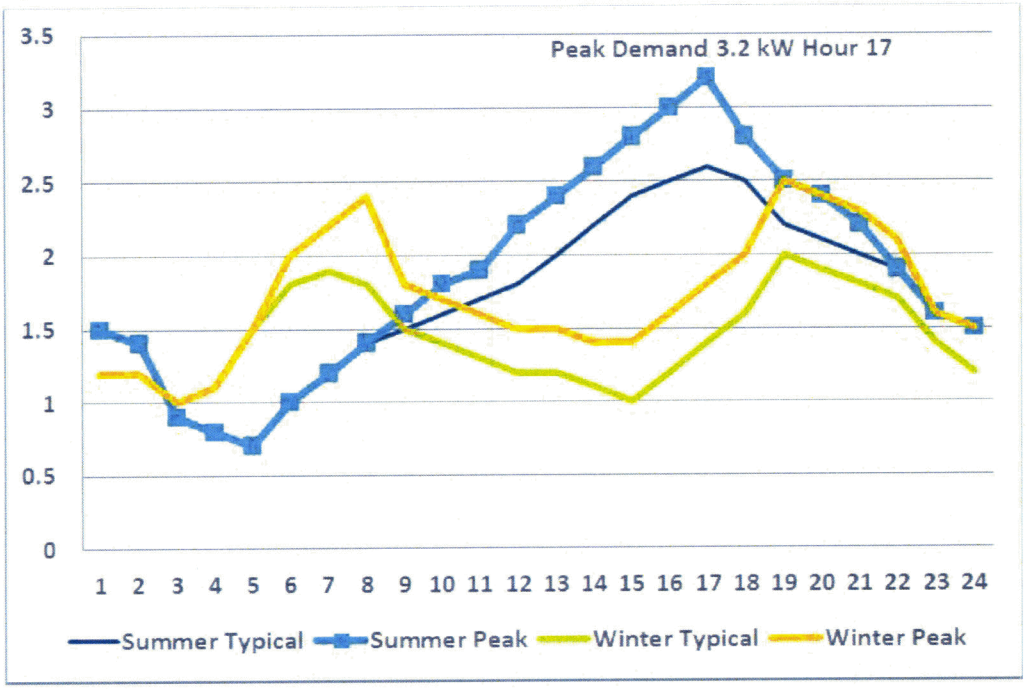

Figure A-1 shows a typical day summer and winter load shape and the peak day for both seasons. The peak hour demand for this customer occurs in the summer and is 3.2 kW. This is the customer's non-coincident peak demand based on an hourly measure. Hourly demand averages the kWh usage over the underlying measurement interval. For example, this demand may be average over four-15 minute intervals as illustrated in Figure A-2.

Figure A-2 Summer Peak Hour kW per Interval

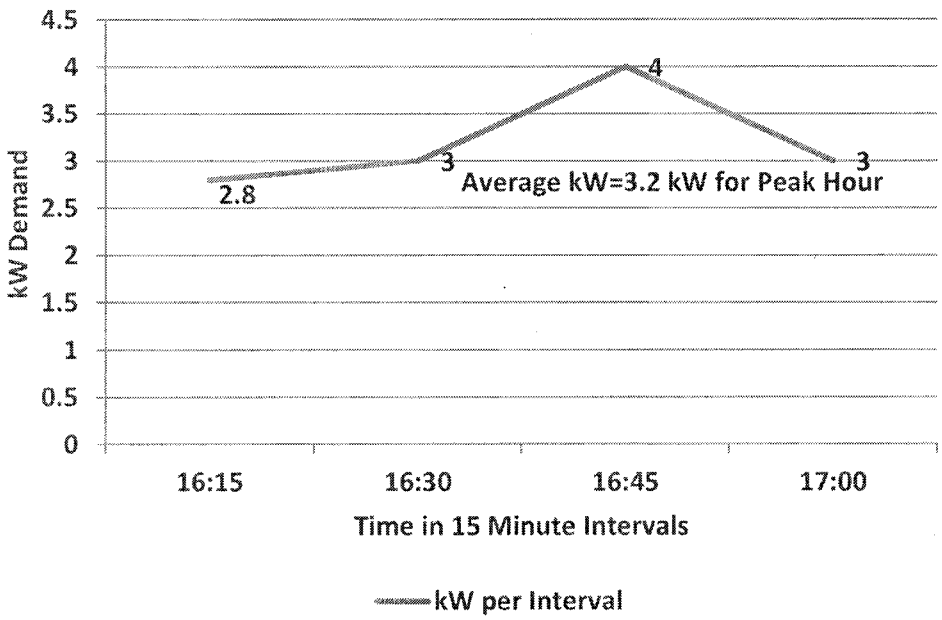

Figure A-2 illustrates the averaging of four-15 minute intervals to derive the customer's maximum demand. Maximum demand is also measured using shorter intervals. Table A-1 provides the demand in kW for each of the three possible measurement intervals.

INTERVAL	kW DEMAND
15 Minutes	4 kW
30 Minutes	3.5 kW
60 Minutes	3.2 kW

Since the kW measure of capacity required to meet the customer's load is the maximum demand on the utility system, the 15-minute interval is more representative of the required capacity for the utility's local distribution facilities. In any event, the choice of the measurement interval has little impact on customers' bills except for customers with highly variable loads. The reason for this is the costs are fixed and the higher measure of demand results in a lower unit charge for the customer.

As discussed earlier, there are many different billing demands that are relevant for cost recovery purposes. The same method of calculation is used in each instance although the hour or hours of measurement may differ. That is, some measures of demand might be defined as occurring within a specific range of hours. For example, the demand may be defined as occurring between the hours of 1 p.m. and -4 p.m. Since our data is reported on an hour-ended basis, the peak demand would be measured as the maximum demand occurring during the hours of 14 through 16 above. In that case, the demand would be 3 kW occurring at hour 16.

Exhibit HEO – R – 1

TABLE 11. ILLUSTRATIVE SUMMARY OF ASSIGNMENT OF FUNCTIONAL COST ELEMENTS TO PARAMETRIC COMPONENTS OF COST-TO-SERVE OF FOUR GENERAL CLASSES OF SERVICE

	"Customer" Component				"Customer Demand" Component				"Class Peak or Diversified Demand" Component				"Energy" Component			
	Mfg. & Nonmfg.			Res.	Mfg. & Nonmfg.			Res.	Mfg. & Nonmfg.			Res.	Mfg. & Nonmfg.			Res.
	HT	PD	Sec.	Sec.	HT	PD	Sec.	Sec.	HT	PD	Sec.	Sec.	HT	PD	Sec.	Sec.
Production system	–	–	–	–	–	–	–	–	X	X	X	X	X	X	X	X
Bulk transmission system	–	–	–	–	–	–	–	–	X	X	X	X	–	–	–	–
Distribution system																
High Tension distribution (Substations & lines)	–	–	–	–	X	–	–	–	–	X	X	X	–	–	–	–
Primary voltage distribution																
Substations	–	–	–	–	–	–	–	–	–	X	X	X	–	–	–	–
Capacitors	–	–	–	–	–	–	–	–	–	X	X	X	–	–	–	–
Feeders	–	–	–	–	–	X	–	–	–	–	X	X	–	–	–	–
Branches	–	X	X	X	–	–	X	X	–	–	–	–	–	–	–	–
Secondary voltage distribution																
Transformers	–	–	X	X	–	–	X	X	–	–	X	X	–	–	–	–
Capacitors	–	–	–	–	–	–	–	–	–	–	X	X	–	–	–	–
Mains	–	–	X	X	–	–	–	–	–	–	–	–	–	–	–	–
Service conductors	X	X	X	X	–	–	–	–	–	–	–	–	–	–	–	–
Metering and control system	X	X	X	X	–	–	–	–	–	–	–	–	–	–	–	–
Work on consumers' premises	X	X	X	X	–	–	–	–	–	–	–	–	–	–	–	–
Customers' accounting	X	X	X	X	–	–	–	–	–	–	–	–	–	–	–	–
Sales promotion	X	X	X	X	X	X	X	–	–	–	–	–	–	–	–	–
General administrative:																
General plant (carrying charges)	←(at fixed rate per dollar of foregoing plant)→															
General & administrative expenses	← at fixed rate per dollar of direct expenses (excluding fuel, energy purchases, and fixed charges) →															
Total cost-to-serve per unit of the parameter as at meters	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X

Note: Functional costs include expenses and carrying charges on investment in plant and working capital.

Exhibit HEO – R – 2

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
I. ELECTRIC PLANT IN SERVICE									
A. INTANGIBLE PLANT									
Intangible Plant	301-303	160,246,771	92,889,664	2,051,982	33,006,195	16,114,538	11,847,834	3,184,513	1,152,044
Subtotal - INTANGIBLE PLANT	301-303	160,246,771	92,889,664	2,051,982	33,006,195	16,114,538	11,847,834	3,184,513	1,152,044
B. PRODUCTION PLANT									
STEAM PRODUCTION PLANT									
Land & Land Rights	310	6,057,619	3,119,315	69,694	1,391,363	740,686	532,776	203,784	0
StructuresImprovements	311	195,860,951	100,856,786	2,253,420	44,986,944	23,948,596	17,226,257	6,588,948	0
Boiler Plant Equipment	312	1,000,007,373	514,944,551	11,505,288	229,689,865	122,274,363	87,952,109	33,641,196	0
Reactor Plant Equipment	322	0	0	0	0	0	0	0	0
Turbogenerator Units	314	294,774,517	151,791,412	3,391,441	67,706,220	36,043,100	25,925,849	9,916,494	0
Accessory Electric Equipment	315	134,465,967	69,242,007	1,547,058	30,885,242	16,441,619	11,826,478	4,523,563	0
Miscellaneous Power Plant Equipment	316	25,580,106	13,172,239	294,304	5,875,448	3,127,768	2,249,808	860,539	0
Sundt/SPV/SGS1 Acquisition Adjustment	114	-31,854,390	-16,403,124	-366,491	-7,316,577	-3,894,947	-2,801,640	-1,071,612	0
Electric Plant Purchased or Sold	102	15,029	7,739	173	3,452	1,838	1,322	506	0
OTHER PRODUCTION PLANT									
Land and Land Rights	340	1,873,363	964,671	21,553	430,289	229,063	164,765	63,022	0
Structures and Improvements	341	21,065,337	10,847,400	242,361	4,838,459	2,575,732	1,852,727	708,658	0
Boiler Plant Equipment	342	17,936,074	9,236,015	206,358	4,119,704	2,193,106	1,577,504	603,387	0
Reactor Plant Equipment	343	181,875,041	93,654,871	2,092,509	41,774,546	22,238,491	15,996,175	6,118,449	0
Engines and Generators	344	244,472,493	125,888,850	2,812,706	56,152,440	29,892,498	21,501,713	8,224,286	0
Turbogenerator Units	345	12,398,839	6,384,667	142,651	2,847,867	1,516,049	1,090,496	417,109	0
Accessory Electric Equipment	346&347	13,743,196	7,076,932	158,118	3,156,650	1,680,428	1,208,734	462,334	0
Misc. Power Plant Equipment	114	-37,278,677	-19,196,310	-428,899	-8,562,471	-4,558,193	-3,278,714	-1,254,090	0
Subtotal - PRODUCTION PLANT	304-346	2,080,992,837	1,071,588,022	23,942,246	477,979,440	254,450,197	183,026,359	70,006,572	0
C. TRANSMISSION PLANT									
Land and Land Rights	350	0	0	0	0	0	0	0	0
Structures and Improvements	352	0	0	0	0	0	0	0	0
Station Equipment	353	0	0	0	0	0	0	0	0
Towers and Fixtures	354	0	0	0	0	0	0	0	0
Poles and Fixtures	355	0	0	0	0	0	0	0	0
Overhead Conductors and Devices	356	0	0	0	0	0	0	0	0
Underground Conduit	357	0	0	0	0	0	0	0	0
Underground Conductors and Devices	358	0	0	0	0	0	0	0	0
Roads and Trails	359	0	0	0	0	0	0	0	0
Subtotal - TRANSMISSION PLANT	350-359	0	0	0	0	0	0	0	0

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D. DISTRIBUTION PLANT									
Land and Land Rights	360	11,605,107	6,204,731	105,617	2,761,319	1,415,243	1,109,368	0	8,830
Structures and Improvements	361	11,835,474	6,327,898	107,713	2,816,132	1,443,336	1,131,389	0	9,005
Station Equipment	362	161,677,439	86,441,690	1,471,406	38,469,527	19,716,560	15,455,241	0	123,017
Compressor Station Equipment	363	0	0	0	0	0	0	0	0
Poles, Towers and Fixtures	364	233,534,842	171,792,005	4,017,278	33,123,849	10,603,690	8,123,174	0	5,874,847
Overhead Conductors and Devices	365	183,006,168	109,553,312	2,137,495	37,945,458	17,858,051	13,951,321	0	1,560,531
Underground Conduit	366	61,247,158	52,086,600	1,337,060	5,324,180	102,415	2,495	0	2,394,407
Underground Conductors and Devices	367	304,496,075	202,069,335	4,354,196	53,672,692	22,175,997	17,225,188	0	4,998,668
Line Transformers	368	281,381,714	174,269,453	3,484,997	56,998,305	26,189,309	20,439,489	160	0
Services	369	134,848,680	114,679,759	2,943,823	11,722,318	225,488	5,494	0	5,271,798
Meters	370	46,154,903	33,856,083	869,084	10,524,428	0	893,157	12,152	0
Installed on Cust Premise PR_L	371	0	0	0	0	0	0	0	0
Other Property on Customers Premise	372	0	0	0	0	0	0	0	0
Street Lighting and Signals	373	11,995,791	0	0	0	0	0	0	11,995,791
Subtotal - DISTRIBUTION PLANT	374-387	1,441,783,351	957,280,867	20,828,668	253,358,208	99,730,087	78,336,315	12,311	32,236,894
E. GENERAL PLANT									
General Plant	389-399	314,077,737	180,937,543	3,992,924	65,181,072	31,577,691	23,298,616	6,242,578	2,847,314
Subtotal - GENERAL PLANT	389-399	314,077,737	180,937,543	3,992,924	65,181,072	31,577,691	23,298,616	6,242,578	2,847,314
TOTAL PLANT IN SERVICE	101	3,997,100,696	2,302,696,096	50,815,820	829,524,916	401,872,513	296,509,125	79,445,974	36,236,252
ADDITIONS TO UTILITY PLANT									
Energy Conservation Programs	182.3	0	0	0	0	0	0	0	0
Property Held for Future Use	105	0	0	0	0	0	0	0	0
Construction Work in Progress	107	0	0	0	0	0	0	0	0
Nuclear Plant Costs - Calvert Cliffs	182.3	0	0	0	0	0	0	0	0
Total Additions to Utility Plant		0	0	0	0	0	0	0	0
TOTAL UTILITY PLANT		3,997,100,696	2,302,696,096	50,815,820	829,524,916	401,872,513	296,509,125	79,445,974	36,236,252

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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
II. DEPRECIATION RESERVE									
Intangible	301-303	-119,977,698	-69,118,143	-1,525,297	-24,899,170	-12,062,678	-8,900,072	-2,384,665	-1,087,674
Production	304-359	-796,297,495	-410,046,033	-9,161,565	-182,900,116	-97,366,051	-70,035,528	-26,788,203	0
Transmission	350-359	0	0	0	0	0	0	0	0
Land and Land Rights	360	-3,862,742	-2,065,235	-35,154	-919,101	-471,061	-369,251	0	-2,939
Structures and Improvements	361	-3,279,743	-1,753,532	-29,849	-780,382	-399,965	-313,521	0	-2,495
Station Equipment	362	-54,387,561	-29,078,594	-494,974	-12,940,975	-6,632,562	-5,199,073	0	-41,382
Compressor Station Equipment	363	0	0	0	0	0	0	0	0
Poles, Towers and Fixtures	364	-87,160,606	-64,116,751	-1,499,341	-12,362,587	-3,957,542	-3,031,756	0	-2,192,629
Overhead Conductors and Devices	365	-71,943,372	-43,571,875	-853,237	-14,968,663	-7,021,347	-5,484,567	-34	-43,650
Underground Conduit	366	-27,348,184	-23,257,796	-597,026	-2,377,362	-45,730	-1,114	0	-1,069,155
Underground Conductors and Devices	367	-141,085,166	-93,626,775	-2,017,472	-24,868,697	-10,275,023	-7,981,116	0	-2,316,082
Line Transformers	368	-135,774,711	-82,958,836	-1,652,574	-27,387,686	-12,634,865	-9,862,583	0	-1,278,167
Services	369	-52,591,903	-44,725,886	-1,148,111	-4,571,784	-87,942	-2,143	0	-2,056,037
Meters	370	4,020,491	2,949,157	75,705	916,769	0	77,802	1,059	0
Street Lighting and Signals	373	-5,781,491	0	0	0	0	0	0	-5,781,491
General	389-398	-86,548,234	-49,859,710	-1,100,302	-17,961,498	-8,701,646	-6,420,239	-1,720,224	-784,615
Subtotal-DEPRECIATION RESERVE		-1,582,018,414	-911,230,009	-20,039,198	-326,021,251	-159,656,413	-117,523,160	-30,892,067	-16,656,315
Dep. Res.- adjust for 13 month avg.	108.9	0	0	0	0	0	0	0	0
TOTAL RESERVE FOR DEPRECIATION	108	-1,582,018,414	-911,230,009	-20,039,198	-326,021,251	-159,656,413	-117,523,160	-30,892,067	-16,656,315
III. OTHER RATE BASE ITEMS									
Cash Working Capital	n/a	-10,528,676	-6,065,482	-133,853	-2,185,033	-1,058,564	-781,028	-209,267	-95,449
Fuel Inventory	151, 152	25,107,584	12,928,918	288,868	5,766,915	3,069,991	2,208,249	844,643	0
Materials & Supplies	154, 163	77,125,097	44,431,120	980,504	16,005,899	7,754,235	5,721,221	1,532,931	699,188
Prepayments	165	9,439,165	4,552,174	94,946	1,980,218	1,258,831	1,086,594	419,119	47,283
Customer Advances for Construction	252	-11,046,099	-5,906,989	-100,548	-2,628,814	-1,347,330	-1,056,133	0	-6,284
Customer Deposits	235	-19,400,461	-10,374,551	-176,595	-4,617,032	-2,366,340	-1,854,906	0	-11,036
Deferred Credits - Asset Retirement - tax cr	230&253	-2,630,793	-1,515,578	-33,446	-545,973	-264,503	-195,155	-52,289	-23,850
Plant Held for Future Use - Transmission Pl	105	0	0	0	0	0	0	0	0
Regulatory Assets	182	0	0	0	0	0	0	0	0
Regulatory Liabilities	254	25,112,104	14,466,872	319,254	5,211,556	2,524,796	1,862,842	499,126	227,657
ADIT	190	0	0	0	0	0	0	0	0
ADIT - Other Property	283	-403,582,512	-232,500,491	-5,130,813	-83,756,146	-40,576,591	-29,938,174	-8,021,566	-3,658,731
Total - OTHER RATE BASE ITEMS	131-283	-310,404,592	-179,984,007	-3,891,682	-64,768,410	-31,005,474	-22,946,491	-4,987,304	-2,821,223
TOTAL RATE BASE		2,104,677,691	1,211,482,080	26,884,939	438,735,255	211,210,626	156,039,474	43,566,603	16,758,714

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I. OPERATING AND MAINTENANCE EXPE									
A. PRODUCTION EXPENSES									
Operation Supervision & Engineering	500	9,802,746	5,047,833	112,783	2,251,575	1,198,616	862,166	329,774	0
PPFAC - FUEL	501	303,925,690	121,073,677	2,473,168	62,245,531	50,002,169	47,317,185	19,496,303	1,317,657
Steam Expenses	502	21,363,731	11,001,056	245,794	4,906,996	2,612,217	1,878,971	718,696	0
Electric Expenses	505	2,800,879	1,442,287	32,225	643,329	342,473	246,341	94,224	0
Miscellaneous Steam Power Expenses	506	4,495,150	2,314,736	51,718	1,032,483	549,638	395,355	151,221	0
Rents	507	14,157,699	7,290,376	162,887	3,251,856	1,731,111	1,245,190	476,278	0
Maintenance Supervision & Engineering	510	4,146,264	2,135,080	47,704	952,348	506,978	364,670	139,484	0
Maintenance of Structures	511	3,573,450	1,840,115	41,113	820,779	436,938	314,290	120,214	0
Maintenance of Boiler Plant	512	30,090,681	15,494,918	346,199	6,911,474	3,679,292	2,646,519	1,012,279	0
Maintenance of Electric Plant	513	5,140,971	2,647,296	59,148	1,180,820	628,604	452,156	172,947	0
Maintenance Miscellaneous Steam Plant	514	6,697,663	3,448,900	77,058	1,538,374	818,946	589,069	225,316	0
FAS 143 Accretion Expense	411	0	0	0	0	0	0	0	0
Loss from Disposition of Utility Plant	412	0	0	0	0	0	0	0	0
Subtotal - Other Production	500-554	406,194,926	173,736,275	3,649,796	85,735,565	62,506,983	56,311,913	22,936,737	1,317,657
Operation Supervision & Engineering	546	7,586,523	3,906,610	87,284	1,742,535	927,630	667,246	255,218	0
PPFAC - Fuel	547	0	0	0	0	0	0	0	0
Generation Exp & Misc Other Power Gener	548 & 549	1,498,181	771,474	17,237	344,114	183,188	131,767	50,400	0
Rents	550	10,337	5,323	119	2,374	1,264	909	348	0
Maintenance Supervision & Engineering	551	2,193	1,129	25	504	268	193	74	0
Maintenance Structures, Generating, Other	552-554	5,740,669	2,956,105	66,048	1,318,564	701,932	504,900	193,122	0
Other Expenses	557	645,356	332,320	7,425	148,231	78,910	56,760	21,710	0
Subtotal	556-557	15,483,258	7,972,961	178,138	3,556,321	1,893,192	1,361,775	520,871	0
TOTAL PRODUCTION EXPENSE	500-557	421,678,184	181,709,235	3,827,935	89,291,886	64,400,174	57,673,688	23,457,608	1,317,657
B. TRANSMISSION EXPENSE									
Supervision and Engineering	560	0	0	0	0	0	0	0	0
Load Dispatching	561	0	0	0	0	0	0	0	0
Station Expenses	562	0	0	0	0	0	0	0	0
Overhead Line Expenses	563	0	0	0	0	0	0	0	0
Underground Lines Expenses	564	0	0	0	0	0	0	0	0
Transmission by Others	565	95,464,952	49,405,132	840,971	21,986,984	11,268,859	8,833,333	3,059,365	70,310
Miscellaneous Expenses	566	0	0	0	0	0	0	0	0
Rents	567	0	0	0	0	0	0	0	0
Supervision and Engineering	568	0	0	0	0	0	0	0	0
Maintenance of Structures	569	0	0	0	0	0	0	0	0
Maintenance of Station Equipment	570	0	0	0	0	0	0	0	0
Maintenance of Overhead Lines	571	0	0	0	0	0	0	0	0
Maintenance of Underground Lines	572	0	0	0	0	0	0	0	0
Misc Maintenance - Credits	573	0	0	0	0	0	0	0	0
TOTAL TRANSMISSION EXPENSES	560-573	95,464,952	49,405,132	840,971	21,986,984	11,268,859	8,833,333	3,059,365	70,310

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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
C. DISTRIBUTION EXPENSE									
Operation Supervision & Engineering	580	719,344	460,973	9,828	142,377	53,179	43,452	27	9,508
Load Dispatching	581	701,361	375,058	6,384	166,914	85,547	67,058	0	399
Station Expenses	582	263,040	140,663	2,394	62,600	32,084	25,150	0	150
Overhead Line Expenses	583	831,367	497,683	9,710	172,380	81,126	63,379	0	7,089
Underground Line Expenses	584	247,581	164,300	3,540	43,640	18,031	14,006	0	4,064
Street Light and Signal Systems	585	219,325	0	0	0	0	0	0	219,325
Meter Expenses	586	2,764,693	2,027,990	52,058	630,416	0	53,500	728	0
Customer Installation Expenses	587	59,339	43,527	1,117	13,531	0	1,148	16	0
Misc. Distribution Expenses	588	11,306,668	7,511,624	163,457	1,984,910	782,122	614,015	92	250,448
Rents	589	834,309	554,276	12,061	146,465	57,712	45,308	7	18,480
Maint Supervision & Engineering	590	1,054,638	675,838	14,409	208,741	77,966	63,705	40	13,939
Maint of Structures	591	0	0	0	0	0	0	0	0
Maintenance of Station Equipment	592	1,385,470	740,749	12,609	329,659	168,958	132,441	0	1,054
Maintenance of Overhead Lines	593	2,298,053	1,375,687	26,841	476,490	224,248	175,190	0	19,596
Maintenance of Underground Lines	594	132,130	87,684	1,889	23,290	9,623	7,475	0	2,169
Maintenance of Line Transformers	595	155,703	96,432	1,928	31,540	14,492	11,310	0	0
Maintenance of Street Lights	596	0	0	0	0	0	0	0	0
Maintenance of Meters	597	127,603	93,601	2,403	29,097	0	2,469	34	0
Maintenance of Misc. Plant	598	576,162	382,775	8,329	101,146	39,855	31,289	5	12,762
Regulatory Asset Amortization	407	408,531	271,409	5,906	71,718	28,260	22,186	3	9,049
Subtotal - DISTRIBUTION EXPENSES	580-599	24,085,317	15,500,269	334,867	4,634,914	1,673,202	1,373,080	951	568,033
Total - OPER. AND MAINT. EXPENSE	500-599	541,228,453	246,614,635	5,003,773	115,913,784	77,342,236	67,880,101	26,517,924	1,956,000

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D. CUSTOMER ACCOUNTS AND SERVIC									
Supervision	901	0	0	0	0	0	0	0	0
Meter Reading Expenses	902	1,538,844	1,358,784	34,880	138,892	2,672	3,255	362	0
Customer Records & Collection Expense	903	18,299,064	15,527,614	398,593	1,587,199	30,531	37,194	4,133	713,800
Uncollectible Accounts	904	1,723,975	876,942	17,913	604,683	224,436	0	0	0
Misc Customer Accounts Expenses	905	0	0	0	0	0	0	0	0
Subtotal - Customer Accounts Expense	901-905	21,561,883	17,763,340	451,386	2,330,775	257,639	40,448	4,494	713,800
Customer Assistance Exp Electric	(907, 908)	0	0	0	0	0	0	0	0
Supervision	909	202,797	168,941	4,337	17,269	332	405	3,747	7,766
Customer Assistance Expenses	910	109,873	93,439	2,399	9,551	184	4	0	4,295
Information, Instructional Advertising	911	0	0	0	0	0	0	0	0
Misc Customer Serv & Inform Expen	912	0	0	0	0	0	0	0	0
Rents	913	0	0	0	0	0	0	0	0
Subtotal - Customer Service & Info.	909-913	312,669	262,380	6,735	26,820	516	409	3,747	12,062
Supervision	915	0	0	0	0	0	0	0	0
Demonstrating & Selling Expenses	916	0	0	0	0	0	0	0	0
Advertising Expenses	917	0	0	0	0	0	0	0	0
Miscellaneous Sales Expenses	918	0	0	0	0	0	0	0	0
Subtotal - Sales Expense	915-919	0	0	0	0	0	0	0	0
Total - CUST ACCTS, SERVS, & SALES E	901-919	21,874,552	18,025,721	458,121	2,357,595	258,155	40,858	8,241	725,862

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E. ADMINISTRATIVE AND GENERAL									
LABOR RELATED EXPENSES									
Administrative & General Salaries	920	29,996,909	17,204,454	381,861	6,238,598	3,008,207	2,225,437	737,737	200,614
Office Supplies & Expenses	921	11,749,828	6,739,007	149,575	2,443,667	1,178,319	871,707	288,973	78,581
Admin Expenses Transferred-Credit	922	-9,762,376	-5,599,122	-124,275	-2,030,327	-979,009	-724,260	-240,094	-65,289
Outside Services Employed	923	11,102,007	6,367,455	141,329	2,308,937	1,113,353	823,645	273,040	74,248
Employee Pensions and Benefits	926	21,312,336	12,223,496	271,306	4,432,427	2,137,284	1,581,138	524,151	142,533
Subtotal - O & M Accounts 920-923,926	920-926	64,398,703	36,935,290	819,796	13,393,301	6,458,154	4,777,668	1,583,807	430,688
PLANT RELATED EXPENSES									
Property Insurance	924	2,403,431	1,384,596	30,555	498,788	241,643	178,289	47,770	21,789
Injuries and Damages	925	2,054,306	1,183,469	26,117	426,334	206,542	152,391	40,831	18,624
Maintenance of General Plant (also acct 93	935	26,768	15,421	340	5,555	2,691	1,986	532	243
Subtotal - O & M Accounts 924-925	924,925,935	4,484,505	2,583,486	57,012	930,677	450,877	332,665	89,134	40,655
OTHER A&G EXPENSES									
Franchise Requirements	927	0	0	0	0	0	0	0	0
Regulatory Commission Expenses	928	1,326,223	760,864	16,881	275,783	133,021	98,390	32,209	9,075
Duplicate Charges-Credit	929	-375,164	-215,234	-4,775	-78,014	-37,629	-27,833	-9,111	-2,567
General Advertising Expenses	930	5,093,710	2,922,297	64,837	1,059,216	510,902	377,894	123,709	34,854
Miscellaneous General Expenses	930	107,111	61,450	1,363	22,273	10,743	7,946	2,601	733
Rents	931	687,396	394,364	8,750	142,941	68,946	50,997	16,695	4,704
Misc Expenses - Credit	932	0	0	0	0	0	0	0	0
Subtotal	927-932	6,839,276	3,923,740	87,056	1,422,199	685,984	507,395	166,103	46,799
TOTAL A&G EXPENSES	920-932	75,722,484	43,442,516	963,864	15,746,177	7,595,014	5,617,728	1,839,044	518,141
TOTAL OPERATING EXPENSES		638,825,490	308,082,872	6,425,759	134,017,556	85,195,405	73,538,686	28,365,210	3,200,003

TUCSON ELECTRIC POWER COMPANY
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Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
II. DEPRECIATION EXPENSE									
Intangible	301-303	13,277,153	7,648,856	168,795	2,755,430	1,334,898	984,913	263,895	120,366
Production - Steam	500-511	60,024,743	30,452,455	669,780	13,630,703	7,517,151	5,585,177	2,166,051	3,426
Production - Other	546-557	12,557,762	6,466,503	144,480	2,884,369	1,535,481	1,104,474	422,455	0
Transmission	565	0	0	0	0	0	0	0	0
Land & Rights	360	86,658	46,332	789	20,619	10,568	8,284	0	66
Structures & Improvements	361	185,998	99,445	1,693	44,256	22,682	17,780	0	142
Station Equipment	362	2,445,508	1,307,504	22,256	581,884	298,230	233,774	0	1,861
Poles, Towers, & Fixtures	364	3,451,385	2,538,894	59,371	489,534	156,711	120,051	0	86,824
Overhead Conductors & Devices	365	2,779,481	1,683,369	32,964	578,304	271,265	211,892	1	1,686
Underground Conduit	366	750,665	638,390	16,387	65,255	1,255	31	0	29,347
Underground Conductors & Devices	367	4,999,675	3,317,878	71,494	881,279	364,119	282,829	0	82,076
Line Transformers	368	4,903,883	2,996,290	59,687	989,183	456,343	356,215	0	46,165
Services	369	1,916,596	1,629,936	41,840	166,609	3,205	78	0	74,928
Meters	370	2,037,023	1,494,221	38,357	464,490	0	39,419	536	0
Street Lighting & Signal Systems	373	194,790	59,508	1,057	26,492	13,651	10,574	3,713	79,796
Distribution Plant Net Salvage	403	5,407,146	3,115,011	68,742	1,122,154	543,640	401,108	107,472	49,019
General	EDST	14,684,437	8,459,581	186,686	3,047,485	1,476,388	1,089,307	291,866	133,124
TOTAL DEPRECIATION EXPENSES		129,702,903	71,954,174	1,584,377	27,748,046	14,005,587	10,445,904	3,255,991	708,823
III. TAXES									
A. GENERAL TAXES									
Payroll Taxes	408	5,290,439	3,073,455	70,133	1,084,749	518,177	379,593	124,806	39,526
PropertyTaxes - Production	408	14,193,015	7,308,562	163,294	3,259,968	1,735,429	1,248,296	477,466	0
PropertyTaxes - Transmission	408	0	0	0	0	0	0	0	0
PropertyTaxes - Distribution	408	18,111,409	12,032,377	261,831	3,179,496	1,252,830	983,551	148	401,176
PropertyTaxes - General	408	3,070,559	1,768,923	39,037	637,238	308,717	227,777	61,030	27,837
Business Activity Tax - Generation	408	0	0	0	0	0	0	0	0
Business Activity Tax - Transmission	408	69,718	36,081	614	16,057	8,230	6,451	2,234	51
Subtotal - General Taxes		40,735,140	24,219,397	534,908	8,177,508	3,823,383	2,845,668	665,685	468,590
B. FRANCHISE AND REVENUE TAXES									
Franchise Tax T&D	408.11	0	0	0	0	0	0	0	0
PSC Assessment	408.12	0	0	0	0	0	0	0	0
Franchise Tax Prod	408	0	0	0	0	0	0	0	0
Franchise	408.13	0	0	0	0	0	0	0	0
Retail Sales & Other	408.14	0	0	0	0	0	0	0	0
Subtotal - Franchise & Gross Receipts		0	0	0	0	0	0	0	0
Income Taxes - Current		33,355,599	19,215,880	424,055	6,922,343	3,353,605	2,474,353	662,973	302,390
Subtotal - Federal Income Taxes	409-411	33,355,599	19,215,880	424,055	6,922,343	3,353,605	2,474,353	662,973	302,390
TOTAL TAXES		74,090,738	43,435,277	958,964	15,099,851	7,176,988	5,320,021	1,328,658	770,980
TOTAL EXPENSES		842,619,131	423,472,323	8,969,099	176,865,453	106,377,980	89,304,612	32,949,858	4,679,806

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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
IV. OPERATING REVENUES									
Revenues	440-446	927,140,267	407,674,736	3,983,681	263,174,018	111,490,378	99,967,027	36,194,919	4,655,508
Production Other Rev	440-446	0	0	0	0	0	0	0	0
Delayed Payment Charges	440-446	0	0	0	0	0	0	0	0
Reconnect Charges-Missouri	440-446	0	0	0	0	0	0	0	0
Ot Elec Rev-Off-Sys	440-446	0	0	0	0	0	0	0	0
Rent From Elec Property-Mo	440-446	0	0	0	0	0	0	0	0
Miscellaneous Service Revenues Retail	451	6,461,516	5,495,074	141,058	561,695	10,805	263	15	252,607
Scrap Sales Revenues	456	0	0	0	0	0	0	0	0
Other Electric Revenues	447.5, 456.1	25,267,361	11,110,363	108,567	7,172,283	3,038,448	2,724,402	986,420	126,877
Other Electric Revenues - Misc Transmissic	456	0	0	0	0	0	0	0	0
Other Electric - Ancillary	I47.4, 449.1, 456.	0	0	0	0	0	0	0	0
Excess Fac Revenues	450-456	0	0	0	0	0	0	0	0
Total Operating Revenues		958,869,144	424,280,172	4,233,306	270,907,996	114,539,631	102,691,692	37,181,354	5,034,992
Gains/Losses from Energy Purchases		0	0	0	0	0	0	0	0
Allowance for Funds During Construction		0	0	0	0	0	0	0	0
Interest on Customer Deposits		-31,250	-22,929	-589	-7,128	0	-605	0	0
V. NET INCOME		116,218,762	784,921	-4,736,382	94,035,416	8,161,651	13,386,475	4,231,495	355,186
Rate of Return		5.52%	0.06%	-17.62%	21.43%	3.86%	8.58%	9.71%	2.12%

TUCSON ELECTRIC POWER COMPANY
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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
SUMMARY REPORT									
OPERATING REVENUES									
Utility Sales Revenues	440-446	933,601,783	413,169,810	4,124,739	263,735,713	111,501,183	99,967,290	36,194,933	4,908,115
Interdepartmental Revenues	448	0	0	0	0	0	0	0	0
Other Operating Revenues	450-456	0	0	0	0	0	0	0	0
Total Operating Revenues		958,869,144	424,280,172	4,233,306	270,907,996	114,539,631	102,691,692	37,181,354	5,034,992
OPERATING EXPENSES									
Production	500-555	421,678,184	181,709,235	3,827,935	89,291,886	64,400,174	57,673,688	23,457,608	1,317,657
Transmission	560-573	95,464,952	49,405,132	840,971	21,986,984	11,268,859	8,833,333	3,059,365	70,310
Distribution	580-599	24,085,317	15,500,269	334,867	4,634,914	1,673,202	1,373,080	951	568,033
Customer Acctg & Service	901-919	21,874,552	18,025,721	458,121	2,357,595	258,155	40,858	8,241	725,862
Admin & General	920-932	75,722,484	43,442,516	963,864	15,746,177	7,595,014	5,617,728	1,839,044	518,141
Total Operating Expenses		638,825,490	308,082,872	6,425,759	134,017,556	85,195,405	73,538,686	28,365,210	3,200,003
DEPRECIATION EXPENSES	403	129,702,903	71,954,174	1,584,377	27,748,046	14,005,587	10,445,904	3,255,991	708,823
TAXES OTHER THAN INCOME TAX	408	40,735,140	24,219,397	534,908	8,177,508	3,823,383	2,845,668	665,685	468,590
INCOME BEFORE INCOME TAXES		149,605,611	20,023,730	-4,311,738	100,964,886	11,515,256	15,861,434	4,894,468	657,575
INCOME TAXES		0	0	0	0	0	0	0	0
Income Taxes - Current		33,355,599	19,215,880	424,055	6,922,343	3,353,605	2,474,353	662,973	302,390
Subtotal - Federal Income Taxes	409-411	33,355,599	19,215,880	424,055	6,922,343	3,353,605	2,474,353	662,973	302,390
OPERATING INCOME		116,250,012	807,850	-4,735,793	94,042,544	8,161,651	13,387,080	4,231,495	355,186
Gains/Losses		0	0	0	0	0	0	0	0
Allowance for Funds During Construction		0	0	0	0	0	0	0	0
Interest on Customer Deposits		-31,250	-22,929	-589	-7,128	0	-605	0	0
NET INCOME		116,218,762	784,921	-4,736,382	94,035,416	8,161,651	13,386,475	4,231,495	355,186
RATE BASE		2,104,677,691	1,211,482,080	26,884,939	438,735,255	211,210,626	156,039,474	43,566,603	16,758,714
RETURN ON RATE BASE		5.52%	0.06%	-17.62%	21.43%	3.86%	8.58%	9.71%	2.12%
Unitized Rate of Return		1.00	0.01	-3.19	3.88	0.70	1.55	1.76	0.38

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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
REVENUE REQUIREMENTS									
RATE OF RETURN		5.22%	5.52%	5.52%	5.52%	5.52%	5.52%	5.52%	5.52%
Using Target for System RATE BASE		2,104,677,691	1,211,482,080	26,884,939	438,735,255	211,210,626	156,039,474	43,566,603	16,758,714
OPERATING EXPENSES		638,825,490	308,082,872	6,425,759	134,017,556	85,195,405	73,538,686	28,365,210	3,200,003
DEPRECIATION EXPENSE		129,702,903	71,954,174	1,584,377	27,748,046	14,005,587	10,445,904	3,255,991	708,823
GENERAL TAXES		40,735,140	24,219,397	534,908	8,177,508	3,823,383	2,845,668	665,685	468,590
Other costs (benefits), net of taxes		31,250	22,929	589	7,128	0	605	0	0
Subtotal- Operating Costs to recover		809,294,783	404,279,372	8,545,633	169,950,238	103,024,375	86,830,864	32,286,886	4,377,416
Target Return on Rate Base- After taxes		116,218,763	66,897,154	1,484,567	24,226,640	11,662,896	8,616,386	2,405,716	925,404
Actual Historic FIT		33,355,599	19,215,880	424,055	6,922,343	3,353,605	2,474,353	662,973	302,390
Incremental Tax Due to Target ROR		0	0	0	0	0	0	0	0
Subtotal- Rev Req before Uncollectible Adj.		958,869,144	490,392,406	10,454,255	201,099,220	118,040,876	97,921,603	35,355,574	5,605,210
Proforma Incr for Uncollect. Calc		0	0	0	0	0	0	0	0
ECCR & Prop Tax Surcharge		0	0	0	0	0	0	0	0
TOTAL REVENUE REQUIREMENT		958,869,144	490,392,406	10,454,255	201,099,220	118,040,876	97,921,603	35,355,574	5,605,210

Exhibit HEO – R – 3

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
I. ELECTRIC PLANT IN SERVICE									
A. INTANGIBLE PLANT									
Intangible Plant	301-303	160,246,771	92,183,862	2,757,785	33,006,195	16,114,538	11,847,834	3,184,513	1,152,044
Subtotal - INTANGIBLE PLANT	301-303	160,246,771	92,183,862	2,757,785	33,006,195	16,114,538	11,847,834	3,184,513	1,152,044
B. PRODUCTION PLANT									
STEAM PRODUCTION PLANT									
Land & Land Rights	310	6,057,619	3,091,635	97,374	1,391,363	740,686	532,776	203,784	0
StructuresImprovements	311	195,860,951	99,961,810	3,148,396	44,986,944	23,948,596	17,226,257	6,588,948	0
Boiler Plant Equipment	312	1,000,007,373	510,375,071	16,074,769	229,689,865	122,274,363	87,952,109	33,641,196	0
Reactor Plant Equipment	322	0	0	0	0	0	0	0	0
Turbogenerator Units	314	294,774,517	150,444,456	4,738,397	67,706,220	36,043,100	25,925,849	9,916,494	0
Accessory Electric Equipment	315	134,465,967	68,627,571	2,161,493	30,885,242	16,441,619	11,826,478	4,523,563	0
Miscellaneous Power Plant Equipment	316	25,580,106	13,055,352	411,191	5,875,448	3,127,768	2,249,808	860,539	0
Sundt/SPV/SGS1 Acquisition Adjustment	114	-31,854,390	-16,257,567	-512,048	-7,316,577	-3,894,947	-2,801,640	-1,071,612	0
Electric Plant Purchased or Sold	102	15,029	7,671	242	3,452	1,838	1,322	506	0
OTHER PRODUCTION PLANT									
Land and Land Rights	340	1,873,363	956,111	30,114	430,289	229,063	164,765	63,022	0
Structures and Improvements	341	21,065,337	10,751,144	338,618	4,838,459	2,575,732	1,852,727	708,658	0
Boiler Plant Equipment	342	17,936,074	9,154,057	288,316	4,119,704	2,193,106	1,577,504	603,387	0
Reactor Plant Equipment	343	181,875,041	92,823,802	2,923,578	41,774,546	22,238,491	15,996,175	6,118,449	0
Engines and Generators	344	244,472,493	124,771,746	3,929,810	56,152,440	29,892,498	21,501,713	8,224,286	0
Turbogenerator Units	345	12,398,839	6,328,012	199,307	2,847,867	1,516,049	1,090,496	417,109	0
Accessory Electric Equipment	346&347	13,743,196	7,014,133	220,917	3,156,650	1,680,428	1,208,734	462,334	0
Misc. Power Plant Equipment	114	-37,278,677	-19,025,967	-599,242	-8,562,471	-4,558,193	-3,278,714	-1,254,090	0
Subtotal - PRODUCTION PLANT	304-346	2,080,992,837	1,062,079,036	33,451,232	477,979,440	254,450,197	183,026,359	70,006,572	0
C. TRANSMISSION PLANT									
Land and Land Rights	350	0	0	0	0	0	0	0	0
Structures and Improvements	352	0	0	0	0	0	0	0	0
Station Equipment	353	0	0	0	0	0	0	0	0
Towers and Fixtures	354	0	0	0	0	0	0	0	0
Poles and Fixtures	355	0	0	0	0	0	0	0	0
Overhead Conductors and Devices	356	0	0	0	0	0	0	0	0
Underground Conduit	357	0	0	0	0	0	0	0	0
Underground Conductors and Devices	358	0	0	0	0	0	0	0	0
Roads and Trails	359	0	0	0	0	0	0	0	0
Subtotal - TRANSMISSION PLANT	350-359	0	0	0	0	0	0	0	0

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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
D. DISTRIBUTION PLANT									
Land and Land Rights	360	11,605,107	6,118,638	191,710	2,761,319	1,415,243	1,109,368	0	8,830
Structures and Improvements	361	11,835,474	6,240,096	195,515	2,816,132	1,443,336	1,131,389	0	9,005
Station Equipment	362	161,677,439	85,242,279	2,670,817	38,469,527	19,716,560	15,455,241	0	123,017
Compressor Station Equipment	363	0	0	0	0	0	0	0	0
Poles, Towers and Fixtures	364	233,534,842	171,162,072	4,647,211	33,123,849	10,603,690	8,123,174	0	5,874,847
Overhead Conductors and Devices	365	183,006,168	108,470,730	3,220,077	37,945,458	17,858,051	13,951,321	0	1,560,531
Underground Conduit	366	61,247,158	52,086,600	1,337,060	5,324,180	102,415	2,495	0	2,394,407
Underground Conductors and Devices	367	304,496,075	200,732,959	5,690,572	53,672,692	22,175,997	17,225,188	0	4,998,668
Line Transformers	368	281,381,714	172,683,460	5,070,991	56,998,305	26,189,309	20,439,489	160	0
Services	369	134,848,680	114,679,759	2,943,823	11,722,318	225,488	5,494	0	5,271,798
Meters	370	46,154,903	33,856,083	869,084	10,524,428	0	893,157	12,152	0
Installed on Cust Premise PR_L	371	0	0	0	0	0	0	0	0
Other Property on Customers Premise	372	0	0	0	0	0	0	0	0
Street Lighting and Signals	373	11,995,791	0	0	0	0	0	0	11,995,791
Subtotal - DISTRIBUTION PLANT	374-387	1,441,783,351	951,272,677	26,836,858	253,358,208	99,730,087	78,336,315	12,311	32,236,894
E. GENERAL PLANT									
General Plant	389-399	314,077,737	179,554,093	5,376,373	65,181,072	31,577,691	23,298,616	6,242,578	2,847,314
Subtotal - GENERAL PLANT	389-399	314,077,737	179,554,093	5,376,373	65,181,072	31,577,691	23,298,616	6,242,578	2,847,314
TOTAL PLANT IN SERVICE	101	3,997,100,696	2,285,089,668	68,422,248	829,524,916	401,872,513	296,509,125	79,445,974	36,236,252
ADDITIONS TO UTILITY PLANT									
Energy Conservation Programs	182.3	0	0	0	0	0	0	0	0
Property Held for Future Use	105	0	0	0	0	0	0	0	0
Construction Work in Progress	107	0	0	0	0	0	0	0	0
Nuclear Plant Costs - Calvert Cliffs	182.3	0	0	0	0	0	0	0	0
Total Additions to Utility Plant		0	0	0	0	0	0	0	0
TOTAL UTILITY PLANT		3,997,100,696	2,285,089,668	68,422,248	829,524,916	401,872,513	296,509,125	79,445,974	36,236,252

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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
II. DEPRECIATION RESERVE									
Intangible	301-303	-119,977,698	-68,589,665	-2,053,775	-24,899,170	-12,062,678	-8,900,072	-2,384,665	-1,087,674
Production	304-359	-796,297,495	-406,407,394	-12,800,204	-182,900,116	-97,366,051	-70,035,528	-26,788,203	0
Transmission	350-359	0	0	0	0	0	0	0	0
Land and Land Rights	360	-3,862,742	-2,036,579	-63,810	-919,101	-471,061	-369,251	0	-2,939
Structures and Improvements	361	-3,279,743	-1,729,201	-54,179	-780,382	-399,965	-313,521	0	-2,495
Station Equipment	362	-54,387,561	-28,675,118	-898,451	-12,940,975	-6,632,562	-5,199,073	0	-41,382
Compressor Station Equipment	363	0	0	0	0	0	0	0	0
Poles, Towers and Fixtures	364	-87,160,606	-63,881,645	-1,734,446	-12,362,587	-3,957,542	-3,031,756	0	-2,192,629
Overhead Conductors and Devices	365	-71,943,372	-43,146,290	-1,278,821	-14,968,663	-7,021,347	-5,484,567	-34	-43,650
Underground Conduit	366	-27,348,184	-23,257,796	-597,026	-2,377,362	-45,730	-1,114	0	-1,069,155
Underground Conductors and Devices	367	-141,085,166	-93,007,579	-2,636,669	-24,868,697	-10,275,023	-7,981,116	0	-2,316,082
Line Transformers	368	-135,774,711	-82,193,549	-2,417,861	-27,387,686	-12,634,865	-9,862,583	0	-1,278,167
Services	369	-52,591,903	-44,725,886	-1,148,111	-4,571,784	-87,942	-2,143	0	-2,056,037
Meters	370	4,020,491	2,949,157	75,705	916,769	0	77,802	1,059	0
Street Lighting and Signals	373	-5,781,491	0	0	0	0	0	0	-5,781,491
General	389-398	-86,548,234	-49,478,482	-1,481,530	-17,961,498	-8,701,646	-6,420,239	-1,720,224	-784,615
Subtotal-DEPRECIATION RESERVE		-1,582,018,414	-904,180,028	-27,089,179	-326,021,251	-159,656,413	-117,523,160	-30,892,067	-16,656,315
Dep. Res.- adjust for 13 month avg.	108.9	0	0	0	0	0	0	0	0
TOTAL RESERVE FOR DEPRECIATION	108	-1,582,018,414	-904,180,028	-27,089,179	-326,021,251	-159,656,413	-117,523,160	-30,892,067	-16,656,315
III. OTHER RATE BASE ITEMS									
Cash Working Capital	n/a	-10,528,676	-6,019,105	-180,230	-2,185,033	-1,058,564	-781,028	-209,267	-95,449
Fuel Inventory	151, 152	25,107,584	12,814,190	403,596	5,766,915	3,069,991	2,208,249	844,643	0
Materials & Supplies	154, 163	77,125,097	44,091,399	1,320,225	16,005,899	7,754,235	5,721,221	1,532,931	699,188
Prepayments	165	9,439,165	4,508,403	138,588	1,980,313	1,258,866	1,086,594	419,119	47,283
Customer Advances for Construction	252	-11,046,099	-5,825,028	-182,510	-2,628,814	-1,347,330	-1,056,133	0	-6,284
Customer Deposits	235	-19,400,461	-10,230,600	-320,546	-4,617,032	-2,366,340	-1,854,906	0	-11,036
Deferred Credits - Asset Retirement - tax cr	230&253	-2,630,793	-1,503,990	-45,034	-545,973	-264,503	-195,155	-52,289	-23,850
Plant Held for Future Use - Transmission Pl	105	0	0	0	0	0	0	0	0
Regulatory Assets	182	0	0	0	0	0	0	0	0
Regulatory Liabilities	254	25,112,104	14,356,258	429,868	5,211,556	2,524,796	1,862,842	499,126	227,657
ADIT	190	0	0	0	0	0	0	0	0
ADIT - Other Property	283	-403,582,512	-230,722,791	-6,908,513	-83,756,146	-40,576,591	-29,938,174	-8,021,566	-3,658,731
Total - OTHER RATE BASE ITEMS	131-283	-310,404,592	-178,531,264	-5,344,556	-64,768,315	-31,005,439	-22,946,491	-4,987,304	-2,821,223
TOTAL RATE BASE		2,104,677,691	1,202,378,376	35,988,513	438,735,350	211,210,661	156,039,474	43,566,603	16,758,714

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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
I. OPERATING AND MAINTENANCE EXPE									
A. PRODUCTION EXPENSES									
Operation Supervision & Engineering	500	9,802,746	5,003,040	157,576	2,251,575	1,198,616	862,166	329,774	0
PPFAC - FUEL	501	303,925,690	119,781,285	3,765,561	62,245,531	50,002,169	47,317,185	19,496,303	1,317,657
Steam Expenses	502	21,363,731	10,903,435	343,415	4,906,996	2,612,217	1,878,971	718,696	0
Electric Expenses	505	2,800,879	1,429,488	45,023	643,329	342,473	246,341	94,224	0
Miscellaneous Steam Power Expenses	506	4,495,150	2,294,196	72,258	1,032,483	549,638	395,355	151,221	0
Rents	507	14,157,699	7,225,683	227,580	3,251,856	1,731,111	1,245,190	476,278	0
Maintenance Supervision & Engineering	510	4,146,264	2,116,134	66,650	952,348	506,978	364,670	139,484	0
Maintenance of Structures	511	3,573,450	1,823,787	57,442	820,779	436,938	314,290	120,214	0
Maintenance of Boiler Plant	512	30,090,681	15,357,420	483,697	6,911,474	3,679,292	2,646,519	1,012,279	0
Maintenance of Electric Plant	513	5,140,971	2,623,804	82,639	1,180,820	628,604	452,156	172,947	0
Maintenance Miscellaneous Steam Plant	514	6,697,663	3,418,295	107,663	1,538,374	818,946	589,069	225,316	0
FAS 143 Accretion Expense	411	0	0	0	0	0	0	0	0
Loss from Disposition of Utility Plant	412	0	0	0	0	0	0	0	0
Subtotal - Other Production	500-554	406,194,926	171,976,568	5,409,503	85,735,565	62,506,983	56,311,913	22,936,737	1,317,657
Operation Supervision & Engineering	546	7,586,523	3,871,944	121,951	1,742,535	927,630	667,246	255,218	0
PPFAC - Fuel	547	0	0	0	0	0	0	0	0
Generation Exp & Misc Other Power Gener	548 & 549	1,498,181	764,629	24,083	344,114	183,188	131,767	50,400	0
Rents	550	10,337	5,276	166	2,374	1,264	909	348	0
Maintenance Supervision & Engineering	551	2,193	1,119	35	504	268	193	74	0
Maintenance Structures, Generating, Other	552-554	5,740,669	2,929,873	92,279	1,318,564	701,932	504,900	193,122	0
Other Expenses	557	645,356	329,371	10,374	148,231	78,910	56,760	21,710	0
Subtotal	556-557	15,483,258	7,902,211	248,888	3,556,321	1,893,192	1,361,775	520,871	0
TOTAL PRODUCTION EXPENSE	500-557	421,678,184	179,878,779	5,658,391	89,291,886	64,400,174	57,673,688	23,457,608	1,317,657
B. TRANSMISSION EXPENSE									
Supervision and Engineering	560	0	0	0	0	0	0	0	0
Load Dispatching	561	0	0	0	0	0	0	0	0
Station Expenses	562	0	0	0	0	0	0	0	0
Overhead Line Expenses	563	0	0	0	0	0	0	0	0
Underground Lines Expenses	564	0	0	0	0	0	0	0	0
Transmission by Others	565	95,464,952	48,719,616	1,526,486	21,986,984	11,268,859	8,833,333	3,059,365	70,310
Miscellaneous Expenses	566	0	0	0	0	0	0	0	0
Rents	567	0	0	0	0	0	0	0	0
Supervision and Engineering	568	0	0	0	0	0	0	0	0
Maintenance of Structures	569	0	0	0	0	0	0	0	0
Maintenance of Station Equipment	570	0	0	0	0	0	0	0	0
Maintenance of Overhead Lines	571	0	0	0	0	0	0	0	0
Maintenance of Underground Lines	572	0	0	0	0	0	0	0	0
Misc Maintenance - Credits	573	0	0	0	0	0	0	0	0
TOTAL TRANSMISSION EXPENSES	560-573	95,464,952	48,719,616	1,526,486	21,986,984	11,268,859	8,833,333	3,059,365	70,310

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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
C. DISTRIBUTION EXPENSE									
Operation Supervision & Engineering	580	719,344	457,756	13,045	142,377	53,179	43,452	27	9,508
Load Dispatching	581	701,361	369,854	11,588	166,914	85,547	67,058	0	399
Station Expenses	582	263,040	138,711	4,346	62,600	32,084	25,150	0	150
Overhead Line Expenses	583	831,367	492,765	14,628	172,380	81,126	63,379	0	7,089
Underground Line Expenses	584	247,581	163,213	4,627	43,640	18,031	14,006	0	4,064
Street Light and Signal Systems	585	219,325	0	0	0	0	0	0	219,325
Meter Expenses	586	2,764,693	2,027,990	52,058	630,416	0	53,500	728	0
Customer Installation Expenses	587	59,339	43,527	1,117	13,531	0	1,148	16	0
Misc. Distribution Expenses	588	11,306,668	7,464,507	210,574	1,984,910	782,122	614,015	92	250,448
Rents	589	834,309	550,799	15,538	146,465	57,712	45,308	7	18,480
Maint Supervision & Engineering	590	1,054,638	671,122	19,125	208,741	77,966	63,705	40	13,939
Maint of Structures	591	0	0	0	0	0	0	0	0
Maintenance of Station Equipment	592	1,385,470	730,470	22,887	329,659	168,958	132,441	0	1,054
Maintenance of Overhead Lines	593	2,298,053	1,362,093	40,435	476,490	224,248	175,190	0	19,596
Maintenance of Underground Lines	594	132,130	87,104	2,469	23,290	9,623	7,475	0	2,169
Maintenance of Line Transformers	595	155,703	95,555	2,806	31,540	14,492	11,310	0	0
Maintenance of Street Lights	596	0	0	0	0	0	0	0	0
Maintenance of Meters	597	127,603	93,601	2,403	29,097	0	2,469	34	0
Maintenance of Misc. Plant	598	576,162	380,374	10,730	101,146	39,855	31,289	5	12,762
Regulatory Asset Amortization	407	408,531	269,707	7,608	71,718	28,260	22,186	3	9,049
Subtotal - DISTRIBUTION EXPENSES	580-599	24,085,317	15,399,149	435,987	4,634,914	1,673,202	1,373,080	951	568,033
Total - OPER. AND MAINT. EXPENSE	500-599	541,228,453	243,997,544	7,620,864	115,913,784	77,342,236	67,880,101	26,517,924	1,956,000

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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
D. CUSTOMER ACCOUNTS AND SERVIC									
Supervision	901	0	0	0	0	0	0	0	0
Meter Reading Expenses	902	1,538,844	1,358,784	34,880	138,892	2,672	3,255	362	0
Customer Records & Collection Expense	903	18,299,064	15,527,614	398,593	1,587,199	30,531	37,194	4,133	713,800
Uncollectible Accounts	904	1,723,975	859,046	27,006	611,104	226,819	0	0	0
Misc Customer Accounts Expenses	905	0	0	0	0	0	0	0	0
Subtotal - Customer Accounts Expense	901-905	21,561,883	17,745,444	460,479	2,337,195	260,022	40,448	4,494	713,800
Customer Assistance Exp Electric	(907, 908)	0	0	0	0	0	0	0	0
Supervision	909	202,797	168,941	4,337	17,269	332	405	3,747	7,766
Customer Assistance Expenses	910	109,873	93,439	2,399	9,551	184	4	0	4,295
Information, Instructional Advertising	911	0	0	0	0	0	0	0	0
Misc Customer Serv & Inform Expen	912	0	0	0	0	0	0	0	0
Rents	913	0	0	0	0	0	0	0	0
Subtotal - Customer Service & Info.	909-913	312,669	262,380	6,735	26,820	516	409	3,747	12,062
Supervision	915	0	0	0	0	0	0	0	0
Demonstrating & Selling Expenses	916	0	0	0	0	0	0	0	0
Advertising Expenses	917	0	0	0	0	0	0	0	0
Miscellaneous Sales Expenses	918	0	0	0	0	0	0	0	0
Subtotal - Sales Expense	915-919	0	0	0	0	0	0	0	0
Total - CUST ACCTS, SERVS, & SALES E	901-919	21,874,552	18,007,824	467,214	2,364,015	260,538	40,858	8,241	725,862

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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
E. ADMINISTRATIVE AND GENERAL									
LABOR RELATED EXPENSES									
Administrative & General Salaries	920	29,996,909	17,074,919	511,395	6,238,598	3,008,207	2,225,437	737,737	200,614
Office Supplies & Expenses	921	11,749,828	6,688,268	200,314	2,443,667	1,178,319	871,707	288,973	78,581
Admin Expenses Transferred-Credit	922	-9,762,376	-5,556,966	-166,432	-2,030,327	-979,009	-724,260	-240,094	-65,289
Outside Services Employed	923	11,102,007	6,319,514	189,270	2,308,937	1,113,353	823,645	273,040	74,248
Employee Pensions and Benefits	926	21,312,336	12,131,464	363,338	4,432,427	2,137,284	1,581,138	524,151	142,533
Subtotal - O & M Accounts 920-923,926	920-926	64,398,703	36,657,200	1,097,886	13,393,301	6,458,154	4,777,668	1,583,807	430,688
PLANT RELATED EXPENSES									
Property Insurance	924	2,403,431	1,374,010	41,142	498,788	241,643	178,289	47,770	21,789
Injuries and Damages	925	2,054,306	1,174,420	35,166	426,334	206,542	152,391	40,831	18,624
Maintenance of General Plant (also acct 93	935	26,768	15,303	458	5,555	2,691	1,986	532	243
Subtotal - O & M Accounts 924-925	924,925,935	4,484,505	2,563,732	76,766	930,677	450,877	332,665	89,134	40,655
OTHER A&G EXPENSES									
Franchise Requirements	927	0	0	0	0	0	0	0	0
Regulatory Commission Expenses	928	1,326,223	755,129	22,616	275,783	133,021	98,390	32,209	9,075
Duplicate Charges-Credit	929	-375,164	-213,612	-6,398	-78,014	-37,629	-27,833	-9,111	-2,567
General Advertising Expenses	930	5,093,710	2,900,272	86,862	1,059,216	510,902	377,894	123,709	34,854
Miscellaneous General Expenses	930	107,111	60,987	1,827	22,273	10,743	7,946	2,601	733
Rents	931	687,396	391,392	11,722	142,941	68,946	50,997	16,695	4,704
Misc Expenses - Credit	932	0	0	0	0	0	0	0	0
Subtotal	927-932	6,839,276	3,894,168	116,629	1,422,199	685,984	507,395	166,103	46,799
TOTAL A&G EXPENSES	920-932	75,722,484	43,115,100	1,291,280	15,746,177	7,595,014	5,617,728	1,839,044	518,141
TOTAL OPERATING EXPENSES		638,825,490	305,120,469	9,379,358	134,023,977	85,197,788	73,538,686	28,365,210	3,200,003

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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
II. DEPRECIATION EXPENSE									
Intangible	301-303	13,277,153	7,590,373	227,278	2,755,430	1,334,898	984,913	263,895	120,366
Production - Steam	500-511	60,024,743	30,172,417	949,818	13,630,703	7,517,151	5,585,177	2,166,051	3,426
Production - Other	546-557	12,557,762	6,409,121	201,862	2,884,369	1,535,481	1,104,474	422,455	0
Transmission	565	0	0	0	0	0	0	0	0
Land & Rights	360	86,658	45,689	1,432	20,619	10,568	8,284	0	66
Structures & Improvements	361	185,998	98,065	3,073	44,256	22,682	17,780	0	142
Station Equipment	362	2,445,508	1,289,362	40,398	581,884	298,230	233,774	0	1,861
Poles, Towers, & Fixtures	364	3,451,385	2,529,585	68,681	489,534	156,711	120,051	0	86,824
Overhead Conductors & Devices	365	2,779,481	1,666,926	49,406	578,304	271,265	211,892	1	1,686
Underground Conduit	366	750,665	638,390	16,387	65,255	1,255	31	0	29,347
Underground Conductors & Devices	367	4,999,675	3,295,936	93,436	881,279	364,119	282,829	0	82,076
Line Transformers	368	4,903,883	2,968,650	87,328	989,183	456,343	356,215	0	46,165
Services	369	1,916,596	1,629,936	41,840	166,609	3,205	78	0	74,928
Meters	370	2,037,023	1,494,221	38,357	464,490	0	39,419	536	0
Street Lighting & Signal Systems	373	194,790	58,724	1,841	26,492	13,651	10,574	3,713	79,796
Distribution Plant Net Salvage	403	5,407,146	3,091,194	92,559	1,122,154	543,640	401,108	107,472	49,019
General	EDST	14,684,437	8,394,899	251,368	3,047,485	1,476,388	1,089,307	291,866	133,124
TOTAL DEPRECIATION EXPENSES		129,702,903	71,373,488	2,165,064	27,748,046	14,005,587	10,445,904	3,255,991	708,823
III. TAXES									
A. GENERAL TAXES									
Payroll Taxes	408	5,290,439	3,052,653	90,935	1,084,749	518,177	379,593	124,806	39,526
PropertyTaxes - Production	408	14,193,015	7,243,707	228,148	3,259,968	1,735,429	1,248,296	477,466	0
PropertyTaxes - Transmission	408	0	0	0	0	0	0	0	0
PropertyTaxes - Distribution	408	18,111,409	11,956,904	337,304	3,179,496	1,252,830	983,551	148	401,176
PropertyTaxes - General	408	3,070,559	1,755,398	52,562	637,238	308,717	227,777	61,030	27,837
Business Activity Tax - Generation	408	0	0	0	0	0	0	0	0
Business Activity Tax - Transmission	408	69,718	35,580	1,115	16,057	8,230	6,451	2,234	51
Subtotal - General Taxes		40,735,140	24,044,242	710,063	8,177,508	3,823,383	2,845,668	665,685	468,590
B. FRANCHISE AND REVENUE TAXES									
Franchise Tax T&D	408.11	0	0	0	0	0	0	0	0
PSC Assessment	408.12	0	0	0	0	0	0	0	0
Franchise Tax Prod	408	0	0	0	0	0	0	0	0
Franchise	408.13	0	0	0	0	0	0	0	0
Retail Sales & Other	408.14	0	0	0	0	0	0	0	0
Subtotal - Franchise & Gross Receipts		0	0	0	0	0	0	0	0
Income Taxes - Current		33,355,599	19,068,955	570,980	6,922,343	3,353,605	2,474,353	662,973	302,390
Subtotal - Federal Income Taxes	409-411	33,355,599	19,068,955	570,980	6,922,343	3,353,605	2,474,353	662,973	302,390
TOTAL TAXES		74,090,738	43,113,197	1,281,043	15,099,851	7,176,988	5,320,021	1,328,658	770,980
TOTAL EXPENSES		842,619,131	419,607,154	12,825,465	176,871,873	106,380,363	89,304,612	32,949,858	4,679,806

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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
IV. OPERATING REVENUES									
Revenues	440-446	927,140,267	399,453,333	12,205,084	263,174,018	111,490,378	99,967,027	36,194,919	4,655,508
Production Other Rev	440-446	0	0	0	0	0	0	0	0
Delayed Payment Charges	440-446	0	0	0	0	0	0	0	0
Reconnect Charges-Missouri	440-446	0	0	0	0	0	0	0	0
Ot Elec Rev-Off-Sys	440-446	0	0	0	0	0	0	0	0
Rent From Elec Property-Mo	440-446	0	0	0	0	0	0	0	0
Miscellaneous Service Revenues Retail	451	6,461,516	5,495,074	141,058	561,695	10,805	263	15	252,607
Scrap Sales Revenues	456	0	0	0	0	0	0	0	0
Other Electric Revenues	447.5, 456.1	25,267,361	10,886,305	332,625	7,172,283	3,038,448	2,724,402	986,420	126,877
Other Electric Revenues - Misc Transmissic	456	0	0	0	0	0	0	0	0
Other Electric - Ancillary	147.4, 449.1, 456.	0	0	0	0	0	0	0	0
Excess Fac Revenues	450-456	0	0	0	0	0	0	0	0
Total Operating Revenues		958,869,144	415,834,712	12,678,767	270,907,996	114,539,631	102,691,692	37,181,354	5,034,992
Gains/Losses from Energy Purchases		0	0	0	0	0	0	0	0
Allowance for Funds During Construction		0	0	0	0	0	0	0	0
Interest on Customer Deposits		-31,250	-22,929	-589	-7,128	0	-605	0	0
V. NET INCOME		116,218,762	-3,795,371	-147,286	94,028,996	8,159,268	13,386,475	4,231,495	355,186
Rate of Return		5.52%	-0.32%	-0.41%	21.43%	3.86%	8.58%	9.71%	2.12%

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Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
SUMMARY REPORT									
OPERATING REVENUES									
Utility Sales Revenues	440-446	933,601,783	404,948,407	12,346,142	263,735,713	111,501,183	99,967,290	36,194,933	4,908,115
Interdepartmental Revenues	448	0	0	0	0	0	0	0	0
Other Operating Revenues	450-456	0	0	0	0	0	0	0	0
Total Operating Revenues		958,869,144	415,834,712	12,678,767	270,907,996	114,539,631	102,691,692	37,181,354	5,034,992
OPERATING EXPENSES									
Production	500-555	421,678,184	179,878,779	5,658,391	89,291,886	64,400,174	57,673,688	23,457,608	1,317,657
Transmission	560-573	95,464,952	48,719,616	1,526,486	21,986,984	11,268,859	8,833,333	3,059,365	70,310
Distribution	580-599	24,085,317	15,399,149	435,987	4,634,914	1,673,202	1,373,080	951	568,033
Customer Acctg & Service	901-919	21,874,552	18,007,824	467,214	2,364,015	260,538	40,858	8,241	725,862
Admin & General	920-932	75,722,484	43,115,100	1,291,280	15,746,177	7,595,014	5,617,728	1,839,044	518,141
Total Operating Expenses		638,825,490	305,120,469	9,379,358	134,023,977	85,197,788	73,538,686	28,365,210	3,200,003
DEPRECIATION EXPENSES	403	129,702,903	71,373,488	2,165,064	27,748,046	14,005,587	10,445,904	3,255,991	708,823
TAXES OTHER THAN INCOME TAX	408	40,735,140	24,044,242	710,063	8,177,508	3,823,383	2,845,668	665,685	468,590
INCOME BEFORE INCOME TAXES		149,605,611	15,296,513	424,282	100,958,466	11,512,873	15,861,434	4,894,468	657,575
INCOME TAXES		0	0	0	0	0	0	0	0
Income Taxes - Current		33,355,599	19,068,955	570,980	6,922,343	3,353,605	2,474,353	662,973	302,390
Subtotal - Federal Income Taxes	409-411	33,355,599	19,068,955	570,980	6,922,343	3,353,605	2,474,353	662,973	302,390
OPERATING INCOME		116,250,012	-3,772,442	-146,698	94,036,123	8,159,268	13,387,080	4,231,495	355,186
Gains/Losses		0	0	0	0	0	0	0	0
Allowance for Funds During Construction		0	0	0	0	0	0	0	0
Interest on Customer Deposits		-31,250	-22,929	-589	-7,128	0	-605	0	0
NET INCOME		116,218,762	-3,795,371	-147,286	94,028,996	8,159,268	13,386,475	4,231,495	355,186
RATE BASE		2,104,677,691	1,202,378,376	35,988,513	438,735,350	211,210,661	156,039,474	43,566,603	16,758,714
RETURN ON RATE BASE		5.52%	-0.32%	-0.41%	21.43%	3.86%	8.58%	9.71%	2.12%
Unitized Rate of Return		1.00	-0.06	-0.07	3.88	0.70	1.55	1.76	0.38

TUCSON ELECTRIC POWER COMPANY
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Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
REVENUE REQUIREMENTS									
RATE OF RETURN		5.22%	5.52%	5.52%	5.52%	5.52%	5.52%	5.52%	5.52%
Using Target for System									
RATE BASE		2,104,677,691	1,202,378,376	35,988,513	438,735,350	211,210,661	156,039,474	43,566,603	16,758,714
OPERATING EXPENSES		638,825,490	305,120,469	9,379,358	134,023,977	85,197,788	73,538,686	28,365,210	3,200,003
DEPRECIATION EXPENSE		129,702,903	71,373,488	2,165,064	27,748,046	14,005,587	10,445,904	3,255,991	708,823
GENERAL TAXES		40,735,140	24,044,242	710,063	8,177,508	3,823,383	2,845,668	665,685	468,590
Other costs (benefits), net of taxes		31,250	22,929	589	7,128	0	605	0	0
Subtotal- Operating Costs to recover		809,294,783	400,561,128	12,255,073	169,956,658	103,026,758	86,830,864	32,286,886	4,377,416
Target Return on Rate Base- After taxes		116,218,763	66,394,454	1,987,259	24,226,645	11,662,898	8,616,386	2,405,716	925,404
Actual Historic FIT		33,355,599	19,068,955	570,980	6,922,343	3,353,605	2,474,353	662,973	302,390
Incremental Tax Due to Target ROR		0	0	0	0	0	0	0	0
Subtotal- Rev Req before Uncollectible Adj.		958,869,144	486,024,537	14,813,313	201,105,646	118,043,261	97,921,603	35,355,574	5,605,210
Proforma Incr for Uncollect. Calc		0	0	0	0	0	0	0	0
ECCR & Prop Tax Surcharge		0	0	0	0	0	0	0	0
TOTAL REVENUE REQUIREMENT		958,869,144	486,024,537	14,813,313	201,105,646	118,043,261	97,921,603	35,355,574	5,605,210

Exhibit HEO – R – 4

TUCSON ELECTRIC POWER COMPANY
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Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
I. ELECTRIC PLANT IN SERVICE									
A. INTANGIBLE PLANT									
Intangible Plant	301-303	160,246,771	92,491,760	2,449,886	33,006,195	16,114,538	11,847,834	3,184,513	1,152,044
Subtotal - INTANGIBLE PLANT	301-303	160,246,771	92,491,760	2,449,886	33,006,195	16,114,538	11,847,834	3,184,513	1,152,044
B. PRODUCTION PLANT									
STEAM PRODUCTION PLANT									
Land & Land Rights	310	6,057,619	3,120,260	68,749	1,391,363	740,686	532,776	203,784	0
StructuresImprovements	311	195,860,951	100,887,356	2,222,850	44,986,944	23,948,596	17,226,257	6,588,948	0
Boiler Plant Equipment	312	1,000,007,373	515,100,632	11,349,208	229,689,865	122,274,363	87,952,109	33,641,196	0
Reactor Plant Equipment	322	0	0	0	0	0	0	0	0
Turbogenerator Units	314	294,774,517	151,837,420	3,345,433	67,706,220	36,043,100	25,925,849	9,916,494	0
Accessory Electric Equipment	315	134,465,967	69,262,994	1,526,071	30,885,242	16,441,619	11,826,478	4,523,563	0
Miscellaneous Power Plant Equipment	316	25,580,106	13,176,232	290,312	5,875,448	3,127,768	2,249,808	860,539	0
Sundt/SPV/SGS1 Acquisition Adjustment	114	-31,854,390	-16,408,096	-361,519	-7,316,577	-3,894,947	-2,801,640	-1,071,612	0
Electric Plant Purchased or Sold	102	15,029	7,742	171	3,452	1,838	1,322	506	0
OTHER PRODUCTION PLANT									
Land and Land Rights	340	1,873,363	964,963	21,261	430,289	229,063	164,765	63,022	0
Structures and Improvements	341	21,065,337	10,850,688	239,073	4,838,459	2,575,732	1,852,727	708,658	0
Boiler Plant Equipment	342	17,936,074	9,238,815	203,559	4,119,704	2,193,106	1,577,504	603,387	0
Reactor Plant Equipment	343	181,875,041	93,683,258	2,064,122	41,774,546	22,238,491	15,996,175	6,118,449	0
Engines and Generators	344	244,472,493	125,927,007	2,774,549	56,152,440	29,892,498	21,501,713	8,224,286	0
Turbogenerator Units	345	12,398,839	6,386,603	140,716	2,847,867	1,516,049	1,090,496	417,109	0
Accessory Electric Equipment	346&347	13,743,196	7,079,077	155,973	3,156,650	1,680,428	1,208,734	462,334	0
Misc. Power Plant Equipment	114	-37,278,677	-19,202,128	-423,080	-8,562,471	-4,558,193	-3,278,714	-1,254,090	0
Subtotal - PRODUCTION PLANT	304-346	2,080,992,837	1,071,912,822	23,617,446	477,979,440	254,450,197	183,026,359	70,006,572	0
C. TRANSMISSION PLANT									
Land and Land Rights	350	0	0	0	0	0	0	0	0
Structures and Improvements	352	0	0	0	0	0	0	0	0
Station Equipment	353	0	0	0	0	0	0	0	0
Towers and Fixtures	354	0	0	0	0	0	0	0	0
Poles and Fixtures	355	0	0	0	0	0	0	0	0
Overhead Conductors and Devices	356	0	0	0	0	0	0	0	0
Underground Conduit	357	0	0	0	0	0	0	0	0
Underground Conductors and Devices	358	0	0	0	0	0	0	0	0
Roads and Trails	359	0	0	0	0	0	0	0	0
Subtotal - TRANSMISSION PLANT	350-359	0	0	0	0	0	0	0	0

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Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
D. DISTRIBUTION PLANT									
Land and Land Rights	360	11,605,107	6,074,709	235,639	2,761,319	1,415,243	1,109,368	0	8,830
Structures and Improvements	361	11,835,474	6,195,294	240,317	2,816,132	1,443,336	1,131,389	0	9,005
Station Equipment	362	161,677,439	84,630,268	3,282,827	38,469,527	19,716,560	15,455,241	0	123,017
Compressor Station Equipment	363	0	0	0	0	0	0	0	0
Poles, Towers and Fixtures	364	233,534,842	170,840,643	4,968,640	33,123,849	10,603,690	8,123,174	0	5,874,847
Overhead Conductors and Devices	365	183,006,168	107,918,333	3,772,474	37,945,458	17,858,051	13,951,321	0	1,560,531
Underground Conduit	366	61,247,158	52,086,600	1,337,060	5,324,180	102,415	2,495	0	2,394,407
Underground Conductors and Devices	367	304,496,075	200,051,062	6,372,470	53,672,692	22,175,997	17,225,188	0	4,998,668
Line Transformers	368	281,381,714	171,874,192	5,880,258	56,998,305	26,189,309	20,439,489	160	0
Services	369	134,848,680	114,679,759	2,943,823	11,722,318	225,488	5,494	0	5,271,798
Meters	370	46,154,903	33,856,083	869,084	10,524,428	0	893,157	12,152	0
Installed on Cust Premise PR_L	371	0	0	0	0	0	0	0	0
Other Property on Customers Premise	372	0	0	0	0	0	0	0	0
Street Lighting and Signals	373	11,995,791	0	0	0	0	0	0	11,995,791
Subtotal - DISTRIBUTION PLANT	374-387	1,441,783,351	948,206,943	29,902,592	253,358,208	99,730,087	78,336,315	12,311	32,236,894
E. GENERAL PLANT									
General Plant	389-399	314,077,737	180,157,510	4,772,956	65,181,072	31,577,691	23,298,616	6,242,578	2,847,314
Subtotal - GENERAL PLANT	389-399	314,077,737	180,157,510	4,772,956	65,181,072	31,577,691	23,298,616	6,242,578	2,847,314
TOTAL PLANT IN SERVICE	101	3,997,100,696	2,292,769,036	60,742,880	829,524,916	401,872,513	296,509,125	79,445,974	36,236,252
ADDITIONS TO UTILITY PLANT									
Energy Conservation Programs	182.3	0	0	0	0	0	0	0	0
Property Held for Future Use	105	0	0	0	0	0	0	0	0
Construction Work in Progress	107	0	0	0	0	0	0	0	0
Nuclear Plant Costs - Calvert Cliffs	182.3	0	0	0	0	0	0	0	0
Total Additions to Utility Plant		0	0	0	0	0	0	0	0
TOTAL UTILITY PLANT		3,997,100,696	2,292,769,036	60,742,880	829,524,916	401,872,513	296,509,125	79,445,974	36,236,252

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Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
II. DEPRECIATION RESERVE									
Intangible	301-303	-119,977,698	-68,820,170	-1,823,269	-24,899,170	-12,062,678	-8,900,072	-2,384,665	-1,087,674
Production	304-359	-796,297,495	-410,170,319	-9,037,279	-182,900,116	-97,366,051	-70,035,528	-26,788,203	0
Transmission	350-359	0	0	0	0	0	0	0	0
Land and Land Rights	360	-3,862,742	-2,021,957	-78,432	-919,101	-471,061	-369,251	0	-2,939
Structures and Improvements	361	-3,279,743	-1,716,786	-66,595	-780,382	-399,965	-313,521	0	-2,495
Station Equipment	362	-54,387,561	-28,469,240	-1,104,328	-12,940,975	-6,632,562	-5,199,073	0	-41,382
Compressor Station Equipment	363	0	0	0	0	0	0	0	0
Poles, Towers and Fixtures	364	-87,160,606	-63,761,680	-1,854,411	-12,362,587	-3,957,542	-3,031,756	0	-2,192,629
Overhead Conductors and Devices	365	-71,943,372	-42,929,132	-1,495,980	-14,968,663	-7,021,347	-5,484,567	-34	-43,650
Underground Conduit	366	-27,348,184	-23,257,796	-597,026	-2,377,362	-45,730	-1,114	0	-1,069,155
Underground Conductors and Devices	367	-141,085,166	-92,691,629	-2,952,619	-24,868,697	-10,275,023	-7,981,116	0	-2,316,082
Line Transformers	368	-135,774,711	-81,803,054	-2,808,356	-27,387,686	-12,634,865	-9,862,583	0	-1,278,167
Services	369	-52,591,903	-44,725,886	-1,148,111	-4,571,784	-87,942	-2,143	0	-2,056,037
Meters	370	4,020,491	2,949,157	75,705	916,769	0	77,802	1,059	0
Street Lighting and Signals	373	-5,781,491	0	0	0	0	0	0	-5,781,491
General	389-398	-86,548,234	-49,644,762	-1,315,251	-17,961,498	-8,701,646	-6,420,239	-1,720,224	-784,615
Subtotal-DEPRECIATION RESERVE		-1,582,018,414	-907,063,255	-24,205,953	-326,021,251	-159,656,413	-117,523,160	-30,892,067	-16,656,315
Dep. Res.- adjust for 13 month avg.	108.9	0	0	0	0	0	0	0	0
TOTAL RESERVE FOR DEPRECIATION	108	-1,582,018,414	-907,063,255	-24,205,953	-326,021,251	-159,656,413	-117,523,160	-30,892,067	-16,656,315
III. OTHER RATE BASE ITEMS									
Cash Working Capital	n/a	-10,528,676	-6,039,333	-160,001	-2,185,033	-1,058,564	-781,028	-209,267	-95,449
Fuel Inventory	151, 152	25,107,584	12,932,837	284,949	5,766,915	3,069,991	2,208,249	844,643	0
Materials & Supplies	154, 163	77,125,097	44,239,574	1,172,050	16,005,899	7,754,235	5,721,221	1,532,931	699,188
Prepayments	165	9,439,165	4,549,218	97,902	1,980,218	1,258,831	1,086,594	419,119	47,283
Customer Advances for Construction	252	-11,046,099	-5,783,206	-224,332	-2,628,814	-1,347,330	-1,056,133	0	-6,284
Customer Deposits	235	-19,400,461	-10,157,148	-393,998	-4,617,032	-2,366,340	-1,854,906	0	-11,036
Deferred Credits - Asset Retirement - tax cr	230&253	-2,630,793	-1,509,044	-39,979	-545,973	-264,503	-195,155	-52,289	-23,850
Plant Held for Future Use - Transmission Pl	105	0	0	0	0	0	0	0	0
Regulatory Assets	182	0	0	0	0	0	0	0	0
Regulatory Liabilities	254	25,112,104	14,404,504	381,622	5,211,556	2,524,796	1,862,842	499,126	227,657
ADIT	190	0	0	0	0	0	0	0	0
ADIT - Other Property	283	-403,582,512	-231,498,168	-6,133,137	-83,756,146	-40,576,591	-29,938,174	-8,021,566	-3,658,731
Total - OTHER RATE BASE ITEMS	131-283	-310,404,592	-178,860,765	-5,014,925	-64,768,410	-31,005,474	-22,946,491	-4,987,304	-2,821,223
TOTAL RATE BASE		2,104,677,691	1,206,845,016	31,522,003	438,735,255	211,210,626	156,039,474	43,566,603	16,758,714

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
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Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
I. OPERATING AND MAINTENANCE EXPE									
A. PRODUCTION EXPENSES									
Operation Supervision & Engineering	500	9,802,746	5,049,363	111,253	2,251,575	1,198,616	862,166	329,774	0
PPFAC - FUEL	501	303,925,690	122,201,407	1,345,438	62,245,531	50,002,169	47,317,185	19,496,303	1,317,657
Steam Expenses	502	21,363,731	11,004,390	242,460	4,906,996	2,612,217	1,878,971	718,696	0
Electric Expenses	505	2,800,879	1,442,724	31,788	643,329	342,473	246,341	94,224	0
Miscellaneous Steam Power Expenses	506	4,495,150	2,315,438	51,016	1,032,483	549,638	395,355	151,221	0
Rents	507	14,157,699	7,292,586	160,677	3,251,856	1,731,111	1,245,190	476,278	0
Maintenance Supervision & Engineering	510	4,146,264	2,135,727	47,056	952,348	506,978	364,670	139,484	0
Maintenance of Structures	511	3,573,450	1,840,673	40,556	820,779	436,938	314,290	120,214	0
Maintenance of Boiler Plant	512	30,090,681	15,499,615	341,503	6,911,474	3,679,292	2,646,519	1,012,279	0
Maintenance of Electric Plant	513	5,140,971	2,648,098	58,346	1,180,820	628,604	452,156	172,947	0
Maintenance Miscellaneous Steam Plant	514	6,697,663	3,449,945	76,013	1,538,374	818,946	589,069	225,316	0
FAS 143 Accretion Expense	411	0	0	0	0	0	0	0	0
Loss from Disposition of Utility Plant	412	0	0	0	0	0	0	0	0
Subtotal - Other Production	500-554	406,194,926	174,879,967	2,506,104	85,735,565	62,506,983	56,311,913	22,936,737	1,317,657
Operation Supervision & Engineering	546	7,586,523	3,907,794	86,100	1,742,535	927,630	667,246	255,218	0
PPFAC - Fuel	547	0	0	0	0	0	0	0	0
Generation Exp & Misc Other Power Gener	548 & 549	1,498,181	771,708	17,003	344,114	183,188	131,767	50,400	0
Rents	550	10,337	5,324	117	2,374	1,264	909	348	0
Maintenance Supervision & Engineering	551	2,193	1,129	25	504	268	193	74	0
Maintenance Structures, Generating, Other	552-554	5,740,669	2,957,001	65,152	1,318,564	701,932	504,900	193,122	0
Other Expenses	557	645,356	332,421	7,324	148,231	78,910	56,760	21,710	0
Subtotal	556-557	15,483,258	7,975,377	175,721	3,556,321	1,893,192	1,361,775	520,871	0
TOTAL PRODUCTION EXPENSE	500-557	421,678,184	182,855,344	2,681,825	89,291,886	64,400,174	57,673,688	23,457,608	1,317,657
B. TRANSMISSION EXPENSE									
Supervision and Engineering	560	0	0	0	0	0	0	0	0
Load Dispatching	561	0	0	0	0	0	0	0	0
Station Expenses	562	0	0	0	0	0	0	0	0
Overhead Line Expenses	563	0	0	0	0	0	0	0	0
Underground Lines Expenses	564	0	0	0	0	0	0	0	0
Transmission by Others	565	95,464,952	48,369,826	1,876,277	21,986,984	11,268,859	8,833,333	3,059,365	70,310
Miscellaneous Expenses	566	0	0	0	0	0	0	0	0
Rents	567	0	0	0	0	0	0	0	0
Supervision and Engineering	568	0	0	0	0	0	0	0	0
Maintenance of Structures	569	0	0	0	0	0	0	0	0
Maintenance of Station Equipment	570	0	0	0	0	0	0	0	0
Maintenance of Overhead Lines	571	0	0	0	0	0	0	0	0
Maintenance of Underground Lines	572	0	0	0	0	0	0	0	0
Misc Maintenance - Credits	573	0	0	0	0	0	0	0	0
TOTAL TRANSMISSION EXPENSES	560-573	95,464,952	48,369,826	1,876,277	21,986,984	11,268,859	8,833,333	3,059,365	70,310

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
C. DISTRIBUTION EXPENSE									
Operation Supervision & Engineering	580	719,344	456,115	14,686	142,377	53,179	43,452	27	9,508
Load Dispatching	581	701,361	367,199	14,244	166,914	85,547	67,058	0	399
Station Expenses	582	263,040	137,715	5,342	62,600	32,084	25,150	0	150
Overhead Line Expenses	583	831,367	490,255	17,138	172,380	81,126	63,379	0	7,089
Underground Line Expenses	584	247,581	162,659	5,181	43,640	18,031	14,006	0	4,064
Street Light and Signal Systems	585	219,325	0	0	0	0	0	0	219,325
Meter Expenses	586	2,764,693	2,027,990	52,058	630,416	0	53,500	728	0
Customer Installation Expenses	587	59,339	43,527	1,117	13,531	0	1,148	16	0
Misc. Distribution Expenses	588	11,306,668	7,440,466	234,615	1,984,910	782,122	614,015	92	250,448
Rents	589	834,309	549,025	17,312	146,465	57,712	45,308	7	18,480
Maint Supervision & Engineering	590	1,054,638	668,716	21,532	208,741	77,966	63,705	40	13,939
Maint of Structures	591	0	0	0	0	0	0	0	0
Maintenance of Station Equipment	592	1,385,470	725,226	28,132	329,659	168,958	132,441	0	1,054
Maintenance of Overhead Lines	593	2,298,053	1,355,157	47,372	476,490	224,248	175,190	0	19,596
Maintenance of Underground Lines	594	132,130	86,808	2,765	23,290	9,623	7,475	0	2,169
Maintenance of Line Transformers	595	155,703	95,107	3,254	31,540	14,492	11,310	0	0
Maintenance of Street Lights	596	0	0	0	0	0	0	0	0
Maintenance of Meters	597	127,603	93,601	2,403	29,097	0	2,469	34	0
Maintenance of Misc. Plant	598	576,162	379,149	11,955	101,146	39,855	31,289	5	12,762
Regulatory Asset Amortization	407	408,531	268,838	8,477	71,718	28,260	22,186	3	9,049
Subtotal - DISTRIBUTION EXPENSES	580-599	24,085,317	15,347,552	487,584	4,634,914	1,673,202	1,373,080	951	568,033
Total - OPER. AND MAINT. EXPENSE	500-599	541,228,453	246,572,722	5,045,686	115,913,784	77,342,236	67,880,101	26,517,924	1,956,000

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
D. CUSTOMER ACCOUNTS AND SERVIC									
Supervision	901	0	0	0	0	0	0	0	0
Meter Reading Expenses	902	1,538,844	1,358,784	34,880	138,892	2,672	3,255	362	0
Customer Records & Collection Expense	903	18,299,064	15,527,614	398,593	1,587,199	30,531	37,194	4,133	713,800
Uncollectible Accounts	904	1,723,975	885,110	9,745	604,683	224,436	0	0	0
Misc Customer Accounts Expenses	905	0	0	0	0	0	0	0	0
Subtotal - Customer Accounts Expense	901-905	21,561,883	17,771,509	443,218	2,330,775	257,639	40,448	4,494	713,800
Customer Assistance Exp Electric	(907, 908)	0	0	0	0	0	0	0	0
Supervision	909	202,797	168,941	4,337	17,269	332	405	3,747	7,766
Customer Assistance Expenses	910	109,873	93,439	2,399	9,551	184	4	0	4,295
Information, Instructional Advertising	911	0	0	0	0	0	0	0	0
Misc Customer Serv & Inform Expen	912	0	0	0	0	0	0	0	0
Rents	913	0	0	0	0	0	0	0	0
Subtotal - Customer Service & Info.	909-913	312,669	262,380	6,735	26,820	516	409	3,747	12,062
Supervision	915	0	0	0	0	0	0	0	0
Demonstrating & Selling Expenses	916	0	0	0	0	0	0	0	0
Advertising Expenses	917	0	0	0	0	0	0	0	0
Miscellaneous Sales Expenses	918	0	0	0	0	0	0	0	0
Subtotal - Sales Expense	915-919	0	0	0	0	0	0	0	0
Total - CUST ACCTS, SERVS, & SALES E:	901-919	21,874,552	18,033,889	449,953	2,357,595	258,155	40,858	8,241	725,862

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
E. ADMINISTRATIVE AND GENERAL									
LABOR RELATED EXPENSES									
Administrative & General Salaries	920	29,996,909	17,139,168	447,146	6,238,598	3,008,207	2,225,437	737,737	200,614
Office Supplies & Expenses	921	11,749,828	6,713,434	175,148	2,443,667	1,178,319	871,707	288,973	78,581
Admin Expenses Transferred-Credit	922	-9,762,376	-5,577,875	-145,522	-2,030,327	-979,009	-724,260	-240,094	-65,289
Outside Services Employed	923	11,102,007	6,343,292	165,491	2,308,937	1,113,353	823,645	273,040	74,248
Employee Pensions and Benefits	926	21,312,336	12,177,112	317,691	4,432,427	2,137,284	1,581,138	524,151	142,533
Subtotal - O & M Accounts 920-923,926	920-926	64,398,703	36,795,131	959,954	13,393,301	6,458,154	4,777,668	1,583,807	430,688
PLANT RELATED EXPENSES									
Property Insurance	924	2,403,431	1,378,627	36,524	498,788	241,643	178,289	47,770	21,789
Injuries and Damages	925	2,054,306	1,178,366	31,219	426,334	206,542	152,391	40,831	18,624
Maintenance of General Plant (also acct 93	935	26,768	15,354	407	5,555	2,691	1,986	532	243
Subtotal - O & M Accounts 924-925	924,925,935	4,484,505	2,572,348	68,150	930,677	450,877	332,665	89,134	40,655
OTHER A&G EXPENSES									
Franchise Requirements	927	0	0	0	0	0	0	0	0
Regulatory Commission Expenses	928	1,326,223	757,951	19,794	275,783	133,021	98,390	32,209	9,075
Duplicate Charges-Credit	929	-375,164	-214,410	-5,599	-78,014	-37,629	-27,833	-9,111	-2,567
General Advertising Expenses	930	5,093,710	2,911,109	76,025	1,059,216	510,902	377,894	123,709	34,854
Miscellaneous General Expenses	930	107,111	61,215	1,599	22,273	10,743	7,946	2,601	733
Rents	931	687,396	392,854	10,260	142,941	68,946	50,997	16,695	4,704
Misc Expenses - Credit	932	0	0	0	0	0	0	0	0
Subtotal	927-932	6,839,276	3,908,718	102,078	1,422,199	685,984	507,395	166,103	46,799
TOTAL A&G EXPENSES	920-932	75,722,484	43,276,198	1,130,182	15,746,177	7,595,014	5,617,728	1,839,044	518,141
TOTAL OPERATING EXPENSES		638,825,490	307,882,809	6,625,821	134,017,556	85,195,405	73,538,686	28,365,210	3,200,003

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
II. DEPRECIATION EXPENSE									
Intangible	301-303	13,277,153	7,615,882	201,769	2,755,430	1,334,898	984,913	263,895	120,366
Production - Steam	500-511	60,024,743	30,456,794	665,441	13,630,703	7,517,151	5,585,177	2,166,051	3,426
Production - Other	546-557	12,557,762	6,468,463	142,520	2,884,369	1,535,481	1,104,474	422,455	0
Transmission	565	0	0	0	0	0	0	0	0
Land & Rights	360	86,658	45,361	1,760	20,619	10,568	8,284	0	66
Structures & Improvements	361	185,998	97,361	3,777	44,256	22,682	17,780	0	142
Station Equipment	362	2,445,508	1,280,105	49,656	581,884	298,230	233,774	0	1,861
Poles, Towers, & Fixtures	364	3,451,385	2,524,834	73,431	489,534	156,711	120,051	0	86,824
Overhead Conductors & Devices	365	2,779,481	1,658,537	57,796	578,304	271,265	211,892	1	1,686
Underground Conduit	366	750,665	638,390	16,387	65,255	1,255	31	0	29,347
Underground Conductors & Devices	367	4,999,675	3,284,739	104,633	881,279	364,119	282,829	0	82,076
Line Transformers	368	4,903,883	2,954,546	101,432	989,183	456,343	356,215	0	46,165
Services	369	1,916,596	1,629,936	41,840	166,609	3,205	78	0	74,928
Meters	370	2,037,023	1,494,221	38,357	464,490	0	39,419	536	0
Street Lighting & Signal Systems	373	194,790	58,437	2,128	26,492	13,651	10,574	3,713	79,796
Distribution Plant Net Salvage	403	5,407,146	3,101,582	82,171	1,122,154	543,640	401,108	107,472	49,019
General	EDST	14,684,437	8,423,111	223,155	3,047,485	1,476,388	1,089,307	291,866	133,124
TOTAL DEPRECIATION EXPENSES		129,702,903	71,732,300	1,806,252	27,748,046	14,005,587	10,445,904	3,255,991	708,823
III. TAXES									
A. GENERAL TAXES									
Payroll Taxes	408	5,290,439	3,068,177	75,411	1,084,749	518,177	379,593	124,806	39,526
PropertyTaxes - Production	408	14,193,015	7,310,777	161,078	3,259,968	1,735,429	1,248,296	477,466	0
PropertyTaxes - Transmission	408	0	0	0	0	0	0	0	0
PropertyTaxes - Distribution	408	18,111,409	11,918,393	375,815	3,179,496	1,252,830	983,551	148	401,176
PropertyTaxes - General	408	3,070,559	1,761,297	46,662	637,238	308,717	227,777	61,030	27,837
Business Activity Tax - Generation	408	0	0	0	0	0	0	0	0
Business Activity Tax - Transmission	408	69,718	35,325	1,370	16,057	8,230	6,451	2,234	51
Subtotal - General Taxes		40,735,140	24,093,968	660,337	8,177,508	3,823,383	2,845,668	665,685	468,590
B. FRANCHISE AND REVENUE TAXES									
Franchise Tax T&D	408.11	0	0	0	0	0	0	0	0
PSC Assessment	408.12	0	0	0	0	0	0	0	0
Franchise Tax Prod	408	0	0	0	0	0	0	0	0
Franchise	408.13	0	0	0	0	0	0	0	0
Retail Sales & Other	408.14	0	0	0	0	0	0	0	0
Subtotal - Franchise & Gross Receipts		0	0	0	0	0	0	0	0
Income Taxes - Current		33,355,599	19,133,039	506,896	6,922,343	3,353,605	2,474,353	662,973	302,390
Subtotal - Federal Income Taxes	409-411	33,355,599	19,133,039	506,896	6,922,343	3,353,605	2,474,353	662,973	302,390
TOTAL TAXES		74,090,738	43,227,007	1,167,233	15,099,851	7,176,988	5,320,021	1,328,658	770,980
TOTAL EXPENSES		842,619,131	422,842,116	9,599,307	176,865,453	106,377,980	89,304,612	32,949,858	4,679,806

TUCSON ELECTRIC POWER COMPANY
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2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
IV. OPERATING REVENUES									
Revenues	440-446	927,140,267	407,674,736	3,983,681	263,174,018	111,490,378	99,967,027	36,194,919	4,655,508
Production Other Rev	440-446	0	0	0	0	0	0	0	0
Delayed Payment Charges	440-446	0	0	0	0	0	0	0	0
Reconnect Charges-Missouri	440-446	0	0	0	0	0	0	0	0
Ot Elec Rev-Off-Sys	440-446	0	0	0	0	0	0	0	0
Rent From Elec Property-Mo	440-446	0	0	0	0	0	0	0	0
Miscellaneous Service Revenues Retail	451	6,461,516	5,495,074	141,058	561,695	10,805	263	15	252,607
Scrap Sales Revenues	456	0	0	0	0	0	0	0	0
Other Electric Revenues	447.5, 456.1	25,267,361	11,110,363	108,567	7,172,283	3,038,448	2,724,402	986,420	126,877
Other Electric Revenues - Misc Transmissic	456	0	0	0	0	0	0	0	0
Other Electric - Ancillary	447.4, 449.1, 456.	0	0	0	0	0	0	0	0
Excess Fac Revenues	450-456	0	0	0	0	0	0	0	0
Total Operating Revenues		958,869,144	424,280,172	4,233,306	270,907,996	114,539,631	102,691,692	37,181,354	5,034,992
Gains/Losses from Energy Purchases		0	0	0	0	0	0	0	0
Allowance for Funds During Construction		0	0	0	0	0	0	0	0
Interest on Customer Deposits		-31,250	-22,929	-589	-7,128	0	-605	0	0
V. NET INCOME		116,218,762	1,415,128	-5,366,589	94,035,416	8,161,651	13,386,475	4,231,495	355,186
Rate of Return		5.52%	0.12%	-17.02%	21.43%	3.86%	8.58%	9.71%	2.12%

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
SUMMARY REPORT									
OPERATING REVENUES									
Utility Sales Revenues	440-446	933,601,783	413,169,810	4,124,739	263,735,713	111,501,183	99,967,290	36,194,933	4,908,115
Interdepartmental Revenues	448	0	0	0	0	0	0	0	0
Other Operating Revenues	450-456	0	0	0	0	0	0	0	0
Total Operating Revenues		958,869,144	424,280,172	4,233,306	270,907,996	114,539,631	102,691,692	37,181,354	5,034,992
OPERATING EXPENSES									
Production	500-555	421,678,184	182,855,344	2,681,825	89,291,886	64,400,174	57,673,688	23,457,608	1,317,657
Transmission	560-573	95,464,952	48,369,826	1,876,277	21,986,984	11,268,859	8,833,333	3,059,365	70,310
Distribution	580-599	24,085,317	15,347,552	487,584	4,634,914	1,673,202	1,373,080	951	568,033
Customer Acctg & Service	901-919	21,874,552	18,033,889	449,953	2,357,595	258,155	40,858	8,241	725,862
Admin & General	920-932	75,722,484	43,276,198	1,130,182	15,746,177	7,595,014	5,617,728	1,839,044	518,141
Total Operating Expenses		638,825,490	307,882,809	6,625,821	134,017,556	85,195,405	73,538,686	28,365,210	3,200,003
DEPRECIATION EXPENSES	403	129,702,903	71,732,300	1,806,252	27,748,046	14,005,587	10,445,904	3,255,991	708,823
TAXES OTHER THAN INCOME TAX	408	40,735,140	24,093,968	660,337	8,177,508	3,823,383	2,845,668	665,685	468,590
INCOME BEFORE INCOME TAXES		149,605,611	20,571,096	-4,859,104	100,964,886	11,515,256	15,861,434	4,894,468	657,575
INCOME TAXES		0	0	0	0	0	0	0	0
Income Taxes - Current		33,355,599	19,133,039	506,896	6,922,343	3,353,605	2,474,353	662,973	302,390
Subtotal - Federal Income Taxes	409-411	33,355,599	19,133,039	506,896	6,922,343	3,353,605	2,474,353	662,973	302,390
OPERATING INCOME		116,250,012	1,438,057	-5,366,000	94,042,544	8,161,651	13,387,080	4,231,495	355,186
Gains/Losses		0	0	0	0	0	0	0	0
Allowance for Funds During Construction		0	0	0	0	0	0	0	0
Interest on Customer Deposits		-31,250	-22,929	-589	-7,128	0	-605	0	0
NET INCOME		116,218,762	1,415,128	-5,366,589	94,035,416	8,161,651	13,386,475	4,231,495	355,186
RATE BASE		2,104,677,691	1,206,845,016	31,522,003	438,735,255	211,210,626	156,039,474	43,566,603	16,758,714
RETURN ON RATE BASE		5.52%	0.12%	-17.02%	21.43%	3.86%	8.58%	9.71%	2.12%
Unitized Rate of Return		1.00	0.02	-3.08	3.88	0.70	1.55	1.76	0.38

TUCSON ELECTRIC POWER COMPANY
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Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
REVENUE REQUIREMENTS									
RATE OF RETURN		5.22%	5.52%	5.52%	5.52%	5.52%	5.52%	5.52%	5.52%
Using Target for System									
RATE BASE		2,104,677,691	1,206,845,016	31,522,003	438,735,255	211,210,626	156,039,474	43,566,603	16,758,714
OPERATING EXPENSES		638,825,490	307,882,809	6,625,821	134,017,556	85,195,405	73,538,686	28,365,210	3,200,003
DEPRECIATION EXPENSE		129,702,903	71,732,300	1,806,252	27,748,046	14,005,587	10,445,904	3,255,991	708,823
GENERAL TAXES		40,735,140	24,093,968	660,337	8,177,508	3,823,383	2,845,668	665,685	468,590
Other costs (benefits), net of taxes		31,250	22,929	589	7,128	0	605	0	0
Subtotal- Operating Costs to recover		809,294,783	403,732,006	9,092,999	169,950,238	103,024,375	86,830,864	32,286,886	4,377,416
Target Return on Rate Base- After taxes		116,218,763	66,641,099	1,740,622	24,226,640	11,662,896	8,616,386	2,405,716	925,404
Actual Historic FIT		33,355,599	19,133,039	506,896	6,922,343	3,353,605	2,474,353	662,973	302,390
Incremental Tax Due to Target ROR		0	0	0	0	0	0	0	0
Subtotal- Rev Req before Uncollectible Adj.		958,869,144	489,506,144	11,340,517	201,099,220	118,040,876	97,921,603	35,355,574	5,605,210
Proforma Incr for Uncollect. Calc		0	0	0	0	0	0	0	0
ECCR & Prop Tax Surcharge		0	0	0	0	0	0	0	0
TOTAL REVENUE REQUIREMENT		958,869,144	489,506,144	11,340,517	201,099,220	118,040,876	97,921,603	35,355,574	5,605,210

Rebuttal Testimony of

Craig A. Jones

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

Rebuttal Testimony of

Craig A. Jones

on Behalf of

Tucson Electric Power Company

July 25, 2016

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Exhibits:

Exhibit CAJ-R-1 - Summary of Changes from Application

Exhibit CAJ-R-2 - Summary of Bill Impacts

Exhibit CAJ-R-3 - Revised Schedule H-1 through H-4

Exhibit CAJ-R-4 - Summary of Frozen Lifeline Rates

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Craig A. Jones and my business address is 88 East Broadway, Tucson, Arizona, 85702.

Q. Did you file Direct Testimony in this proceeding?

A. Yes.

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. My Rebuttal Testimony is filed on behalf of Tucson Electric Power Company ("TEP" or "Company").

Q. In general, what is the Company's concern with certain positions being expressed by many of the parties in this case?

A. Staff and the Company are the only parties in this case that have an interest that goes beyond a specific customer class, a small group of customers or a narrow special interest. The Company's filed case was an attempt to move to a more equitable rate design with the goal of eventually eliminating intra- or inter-class subsidies where possible or appropriate. In my Rebuttal Testimony, I explain why certain proposals by many of the parties in this case create either larger or additional subsidies for their specific special interest, or those proposals do not adhere to widely accepted rate design principles.

Q. What are the primary reasons for updating TEP's rate design?

A. In this proceeding, the Company is attempting to modify its rates to:

(1) reduce intra-class subsidies where possible;

(2) promote fairness between similarly situated customers;

(3) recover costs from cost causers;

(4) provide rates designed to promote flexibility to accommodate changing customer usage patterns while still recovering costs;

(5) promote rate structures that encourage the optimal integration of new energy technologies on the electric system;

(6) ensure that the Company continues delivering safe, reliable and affordable electric services for the benefit of all of our customers; and

(7) ensure the Company has a reasonable opportunity to achieve its authorized rate of return.

Q. Which Commission Staff and/or Intervenor testimony do you address in your Rebuttal Testimony?

A. I will be addressing the rate design testimony of most witnesses, including Staff, Residential Utility Consumers Office ("RUCO"), Arizonans for Electric Choice & Competition ("AECC"), Arizona Community Action Association ("ACAA"), Southwest Energy Efficiency Project ("SWEEP") and Western Resource Advocates ("WRA"), Wal-Mart, SOLON Corporation ("SOLON"), Vote Solar Initiative ("Vote Solar"), Energy Freedom Coalition of America ("EFCA"), The Kroger Co. ("Kroger") and Noble Americas Energy Solutions ("Noble"). I will not have any Rebuttal Testimony for AIC, DOD or APS other than to say I support most of their positions. While the areas I will be addressing in this Rebuttal Testimony are of most concern to me at this time, the fact that I did not specifically address a particular party's position or opinion, does not mean I agree with it and therefore I reserve the right to address any additional topics I deem necessary in my Rejoinder testimony or during the hearings.

II. SUMMARY OF TESTIMONY.

Q. Would you please provide a quick summary of your testimony?

A. Yes. My Rebuttal Testimony will consist of a total of 12 sections. Sections I and II are the introduction and this summary. Section III provides a quick overview of the rate design related changes the Company is proposing in response to various parties' Direct Testimony.

Section IV reflects the Company's rebuttal of certain positions expressed in Staff's testimony along with discussions providing additional information per various Staff requests. My Rebuttal Testimony is presented in the following order;

i. a summary of the Company's Rebuttal positions,

ii. Staff's suggestion to leave rate design open for a specified period of time,

iii. Staff's proposed revenue allocation that the Company will attempt to move toward,

iv. various responses to questions and suggestions as they relate to the Medium General Service ("MGS"), Large General Service ("LGS") and Large Power Service ("LPS") rate classes,

v. responses to suggested basic service charges and what the Company is willing to accept with minor modifications,

vi. addressing a question relating to the lighting rate class,

vii. responding to questions relating to the Residential Community Solar Program,

viii. a discussion on Lifeline rates and the Company's proposals,

ix. rebuttal of Staff's rejection of the Company's proposed Lost Fixed Cost Recovery ("LFCR") changes,

x. responses relating to questions and suggestions relating to the Prepay program,

xi. the Company's agreement to work with Staff to create a revised Environmental Cost Adjustor ("ECA") Plan of Administration ("POA"), and

xii. a few other miscellaneous items.

Section V is the Company's rebuttal of RUCO and why a higher basic customer charge and two rate tiers are appropriate. I also explain why the Company disagrees with RUCO's Lifeline, weather normalization and net metering related proposals.

Section VI addresses AECC's Class Cost of Service Study ("CCOSS") related issues and concerns he expressed about master metered mobile home parks.

In Sections VVI and VIII, I rebut the ACAA witness with additional support for the Company's Lifeline proposal and the Wal-Mart witness' proposal to create a mechanism to address interclass subsidies between rate cases and other changes.

Section IX is the Company's rebuttal of certain positions and misguided assertions that the Company identified that have not been addressed by other Company witnesses.

Sections X and XI address Kroger, SWEEP and WRA rate design issues and Section XII discusses the Company's objection to the Buy-Through rate in rebuttal to a number of parties' direct testimony on the issue.

III. OVERVIEW OF CHANGES FROM APPLICATION.

Q. Have you summarized the rate design changes the Company is proposing to make in its Rebuttal Testimony?

A. Yes. I have attached **Exhibit CAJ-R-1** which summarizes the key changes the Company is proposing to make to its original filed position in response to rate design Direct Testimony submitted by the various parties to this proceeding.

Q. Would you please provide an overview of the more notable adjustments that the Company is proposing in its Rebuttal Testimony as it relates to rate design?

A. Yes. Below is an overview of the primary adjustments the Company wishes to make at this time which include:

- A revised CCOSS that incorporates either oversights made by the Company in its Direct Testimony or changes suggested by parties to which the Company can agree.
    - Included in the revised CCOSS are adjustments necessary to reflect major usage reductions by the Company's largest customer.
- An adjustment to base fuel to reflect a more current cost of purchased power and fuel.
- Minor adjustments to the non-residential rates to reflect either higher kW caps for a class or expanded provisions to determine when a customer must move to a larger rate class.
- Revised basic service charges, based on Staff's recommendations, to reflect what the Company is willing to accept with the appropriate level of approved revenue requirement and other financial considerations.

- Other conforming changes to move toward Staff's recommended revenue allocations between rate classes using the Company's revised Revenue Requirement.
- The Company supports its proposed three-part rate options, but realizes that based on UNS Electric's recent rate case proceedings a potential third DG option could be discussed that attempts to incorporate certain suggestions by RUCO such as billing options based on current TOU based peak period maximum hourly consumption.
- Additional information in response to various requests or in some cases mischaracterizations made by some parties.
- Any request made by the various parties to incorporate new rates into any CCOSS submitted in the Company's next rate case will be considered and if appropriate included in any proposed CCOSS based on the outcome of this proceeding.
- New counter seasonal rates for certain MGS customers.

I have attached the following **Exhibit CAJ-R-3** to my Rebuttal Testimony which includes the revised H-1 through H-4 Schedules that reflect: (i) the modifications to rate design, (ii) an updated revenue requirement that incorporates adjustments addressed in the Rebuttal testimony of other TEP witnesses and summarized in Company witness David Lewis' Rebuttal Testimony and (iii) revised bill impact calculations.

IV. REBUTTAL OF STAFF WITNESSES.

A. Summary.

Q. Would you summarize the Company's positions as it relates to ACC Staff witness/ Mr. Solganick's Direct Rate Design Testimony in this proceeding?

A. Yes. Mr. Solganick starts with a summary of his testimony on page 3. In that summary he states that; "Over the long term, rates should be based on costs and recognize the concepts of customer, demand and energy including time-of-use ("TOU")." The Company agrees with this general concept.

Class Revenue Allocation: Although Staff's revenue allocation proposal does not meet the goals sought by the Company in its Application, the Company is willing to use Staff's suggestion as a guide to adjust the allocation of revenue between the rate classes in the interest of compromise, gradualism and movement in the right direction to eliminate some of the interclass subsidies.

Rate Design: While the Company can accept many of Staff's rate design proposals, the Company believes that certain modifications to Staff's rate design are appropriate and I discuss those modifications in my testimony. The Company is also willing to leave the rate design portion of this proceeding open for a specified period of time in order to make any necessary revenue neutral adjustments to rates to address any significant, unintended consequences that may affect our customers or the Company. Additionally, as explained by Dallas Dukes in his Rebuttal Testimony, the Company believes that customer engagement and education is an important part of implementing any new components in rate design including the addition of a demand charge.

Lifeline Rates/Discounts: The Company strongly supports Staff's suggestion that standardized residential rates be available for Lifeline customers, with a discount available to qualifying customers in place of having special and frozen rates for the Lifeline customers. The specific discount will need to be calculated once final rates are calculated and may involve more than one discount amount for the more highly subsidized groups of frozen Lifeline customers. The Company agrees the total amount of the Lifeline discount should not be reduced, but believes that any increase in the total amount of the discount should be recovered by adjusting the final rates for other customer classes to capture the added discount, or through a process that allows for timely recovery of the additional discounts such as a universal service adjustment.

Net Metering: The Company disagrees with Staff's position that any changes to the existing net metering tariff or waivers of the net metering rules should not be made at this time.

The Company strongly believes that as the result of this rate case a change to the existing net metering rules and related rate design must be made. The Company believes its proposal is the most equitable solution to the current situation created by existing rate design. However, based on the positions of the parties set forth in their Direct Testimonies in this docket and UNS Electric's rate proceeding, the Company recognizes other options may help address the cost shift created by the current rate design when combined with the existing net metering rules. For example, TEP might consider a third three-part rate option that would define billing demand as the maximum monthly peak hourly kWh consumption during the existing TOU on peak period in the three-part Residential and SGS rate classes if combined with the elimination of banking of DG kWh.

Smart Meter opt-out: The Company can accept Staff's recommendation relating to the meter upgrade opt-out.

Buy-Through tariff: The Company does not support the Buy-Through offering and opposes any variation that results in costs being shifted to either the Company or the other customers. Consistent with Staff's recommendation, the Company believes any such cost shifts be addressed before the Buy-Through offering is considered. However, the Company still believes that any non-fuel shifts in cost resulting from any potential Buy-Through offering that might be approved should at a minimum be recovered through the LFCR if not directly recovered from the benefitting entities. The Company is also opposed to allowing any fuel or power cost shifts being created by the Buy-Through rate from being shifted to the Company or the other customers.

LFCR: The Company accepts Staff's recommendation to remove the fixed charge option relating to the LFCR; however, we believe Staff's position on the rest of the requested changes guarantees the Company will not be able to recover lost non-fuel revenues associated with complying with the Commission's Energy Efficiency ("EE") and REST rules. However, without substantial rate design changes being approved in this proceeding, lost fixed cost recovery will continue and the LFCR modifications proposed by the Company will remain appropriate.

I discuss these items in more detail below.

B. Keeping rate design open.

Q. Mr. Solganick, on page 4, line 5, has recommended keeping the rate design portion of the rate case open for some specified period of time to allow for tracking of issues

and revenues associated with transitioning to three-part rates for some customer groups. Is this a concern for the Company?

A. While the Company normally prefers closure to all rate case related issues sooner rather than later, TEP could support keeping the rate design portion of this rate case open for a specified period of time in the event that certain unintended consequences arise that adversely affect the Company or the customers being switched to three-part rates. I will describe the Company's outline of the transitional plan being proposed by the Company for the new MGS customers to establish the particular steps and processes that will need to be executed during the transitional period to make this transition to three-part rates as seamless and issue free as possible.

Q. If the Company agrees with keeping the rate design portion of this case open for a limited period of time, what guidelines would the Company want to be included?

A. The Company believes the following constraints or guidelines should be included:

1) The final transition plan should define how long the rate design remains open, and define the types of adjustments that might be needed to address any potential significant unintended consequences resulting in "outliers" or because of "non-normal" MGS customers (as discussed by Staff). All efforts will be made to minimize or avoid these types of impacts as described later in my testimony, but the possibility should be considered and any resulting changes be kept to a minimum.
2) Any rate design modification should be limited to mitigating these unintended consequences or unintended impacts if they are created and should be open to adjustment of billing determinants and or rates in the specified rate class or classes if it is determined that the information obtained from the original data used to support the initial three-part rates is either under or over stated. These changes should be addressed if the expected revenues (using all available actual data, adjusted for

normal weather) are more (or less) than when the initial rates were created. Any changes should be limited to the MGS rate classes, but may be applied to the other customer classes if needed.

3) Any adjustment to the initial rates should be designed to be revenue neutral to the Company with respect to the intended recovery level for the class. This could include adjusting the demand charge up or down based on actual kW data generated during the transition period, with appropriate adjustments to the volumetric rates to maintain a revenue neutral impact.

C. <u>Revenue allocation.</u>

Q. On Page 24, lines 25-28, Mr. Solganick recommends revenues be allocated in a specific manner. Does the Company agree with his recommendations?

A. In general, the Company understands Mr. Solganick's recommendations, which include a larger portion of Staff's recommended revenue requirement increase to the residential and lighting rate classes with a specified amount being allocated to the other non-residential rate classes. Staff did not want any rate class to see a decrease in rates.

The Company can appreciate Staff's concerns that new rates should be designed to reflect appropriate cost allocation while still setting rates that exhibit the principle of gradualism and will adjust its allocation to reflect something closer to what Staff recommends than what was originally proposed by the Company. The Company still believes additional costs should be shifted from certain large classes to the residential rate classes based on the results of the Company's CCOSS which indicates the large classes are currently subsidizing the residential rate classes. While there may be a number of ways to get there, they all involve allocating more cost to the residential classes and less to the larger rate classes.

As part of the reallocation, the Company first recalculated the total revenues to reflect the adjusted total revenue requirement being recommended by the Company and as shown in Mr. Dukes' Rebuttal Testimony to reflect an approximate $100.6 million increase in test year revenues. The Company then reallocated the revenue requirement in a manner that proportionally followed Staff's suggestion. The Company did allocate an amount that would be proportionally less for the largest rate classes. Schedule H-1 included in **Exhibit CAJ-R-3** reflects that proposed reallocation of revenue recovery to each of the rate classes including an adjustment to fuel costs.

Once the revenue amounts are allocated to each class, a revised revenue proof was developed that uses the same adjusted test year billing determinants used in the Company's Direct Testimony (as adjusted in this rebuttal), using the proposed rate design. Staff's recommended basic service charges are reflected in the revenue calculations and any remaining revenue requirement for the specific rate class is applied to an increase to the volumetric charges and/or demand charges as appropriate in existing rates. All of these changes were made with consideration to typical customer bill impacts being kept within an acceptable range, knowing that there will always be a few outliers. Billing determinants for on- and off-peak volumes were used to determine on- and off-peak fuel recoveries. A summary of the resulting bill impacts are reflected in **Exhibit CAJ-R-2**.

Q. Did you include bill impact calculations for the various customer classes?

A. Yes. In addition to the summary of bill impacts provided in **Exhibit CAJ-R-2**, I am attaching a version of the H Schedules as **Exhibit CAJ-R-3.** The specific rates are reflected in Schedule H-3 and 85 pages of bill impacts are reflected in Schedule H-4. These exhibits include rates and bill impacts for all rate classes.

D. <u>MGS, LGS and LPS classifications.</u>

Q. With regards to the MGS class, Mr. Solganick, at page 34, line 10, has expressed concern over the abruptness of moving a customer from the MGS class to the LGS class in the first month after a customer hits the MGS cap of 250 kW. How does the Company regard this concern?

A. After some thought and discussion, the Company is proposing two changes to the MGS tariff. The first change is to increase the cap from 250 kW to 300 kW. The second is to change the language from "any customer exceeding the cap for a billing month will automatically be moved, in the subsequent month, to the new LGS rate class" to "any customer exceeding the cap for a second billing month in a 12-month rolling period will automatically be moved, in the subsequent month, to the LGS rate class". The Company will communicate with the customer, via a letter, after the first month they exceed the cap to warn them that if they exceed the cap for a second time in the next 11 months, they will be moved to the LGS rate.

Q. Why did the Company decide to propose the new MGS cap of 300 kW?

A. The Company came to realization that raising the cap from 250 kW to 300 kW would better ensure that the customer is on the correct rate. If a customer hits 300 kW, the customer will have a billed demand of at least 225 kW for the next 11 months, which is greater than the 200 kW minimum on the LGS class. With a billing demand greater than the minimum, plus lower energy rates on the LGS tariff, most customers should save money in the LGS class.

To demonstrate this, the Company looked at its smallest LGS customers. The reason for modeling bill impacts using the LGS customers is the existence of readily available demand data. The Company identified 27 customers whose maximum test year demand

was between 285 kW and 316 kW. The Company created bill impacts based on the tariff numbers and found that all but two of these customers save money on the LGS rate. Please see the following table which summarizes this information:

Customer	min kW	max KW	kWh	Load Factor	MGS Annual	LGS Annual	LGS-MGS	Percent Change
Customer 1	172	285	918,720	36.8%	$120,978	$109,963	($11,015)	-9%
Customer 2	165	286	803,200	32.1%	$108,169	$104,920	($3,249)	-3%
Customer 3	189	286	1,196,480	47.7%	$153,492	$128,354	($25,137)	-16%
Customer 4	198	288	1,073,800	42.6%	$139,108	$121,771	($17,337)	-12%
Customer 5	162	288	755,400	29.9%	$101,790	$101,473	($317)	0%
Customer 6	182	288	1,301,400	51.5%	$164,885	$133,686	($31,199)	-19%
Customer 7	184	288	1,426,176	56.5%	$178,737	$139,911	($38,826)	-22%
Customer 8	210	290	1,629,200	64.0%	$202,170	$152,891	($49,279)	-24%
Customer 9	190	291	1,212,320	47.5%	$154,571	$128,068	($26,503)	-17%
Customer 10	184	291	1,120,640	43.9%	$143,239	$120,809	($22,430)	-16%
Customer 11	184	295	631,440	24.4%	$89,094	$96,621	$7,527	8%
Customer 12	188	296	730,920	28.2%	$101,027	$104,038	$3,011	3%
Customer 13	210	296	816,200	31.5%	$109,817	$107,408	($2,409)	-2%
Customer 14	158	296	1,267,800	48.8%	$161,289	$131,923	($29,365)	-18%
Customer 15	210	298	1,444,000	55.3%	$181,643	$143,765	($37,878)	-21%
Customer 16	214	300	1,059,120	40.3%	$135,882	$119,972	($15,910)	-12%
Customer 17	193	300	1,344,480	51.2%	$168,305	$134,714	($33,591)	-20%
Customer 18	156	302	994,720	37.6%	$130,543	$117,132	($13,411)	-10%
Customer 19	204	306	1,176,000	43.9%	$151,474	$128,417	($23,056)	-15%
Customer 20	249	307	1,706,400	63.4%	$210,576	$158,850	($51,726)	-25%
Customer 21	198	309	1,136,880	42.0%	$146,260	$125,390	($20,870)	-14%
Customer 22	159	312	991,200	36.3%	$131,946	$121,327	($10,619)	-8%
Customer 23	178	312	1,129,360	41.3%	$146,413	$126,948	($19,465)	-13%
Customer 24	134	313	973,400	35.5%	$127,804	$115,377	($12,427)	-10%
Customer 25	219	314	880,560	32.0%	$118,224	$113,387	($4,837)	-4%
Customer 26	207	316	1,288,320	46.6%	$165,917	$138,998	($26,919)	-16%
Customer 27	119	316	875,000	31.6%	$118,526	$116,290	($2,236)	-2%

Q. Does the Company intend to propose and implement a plan to transition the current SGS customers who qualify for movement to the new MGS rate class?

A. Yes. The Company will develop multiple forms of communication for the affected customers and has developed a plan to inform these customers before being moved to the new MGS rate that I will discuss later in this testimony.

Q. Mr. Solganick has requested that the Company delay the application of the ratchet provision of the proposed MGS rate class in his Direct Testimony at page 34, line 4. What is the Company's response to this suggestion?

A. The Company believes these customers are large enough to adapt to the ratchet provision right away. Additionally, the rates that have been calculated assume the ratchet will apply. If the application of the ratchet is delayed, the rate would have to be increased an appropriate amount to reflect what would be a lower number of demand billing determinants. Since the ratchet examines demand levels for the prior 11-months for billing purposes, the Company would prefer not eliminating the ratchet totally because that would not provide the customer with the appropriate feedback on how they utilize the system. As discussed below, the Company's proposed transition period for these customers will allow 9 months for the customer to adapt to a demand charge before it is reflected on the customer's bill. The Company believes this addresses Mr. Solganick's concern.

Q. Has the Company identified any other mitigation measures for this group of migrating customers?

A. Yes. The Company was able to identify a handful of accounts that are extremely counter seasonal. These accounts draw significant power for a short period of time during the low use winter period. To limit the impact of the ratchet on these customers, the Company is proposing to amend the MGS tariff to include a seasonality clause. The Company is proposing to add a provision to the MGS tariff that will apply to those full requirements customers who consume 90% or more of their kWh during the winter period (October-April, as defined by the TEP tariffs). The provision includes: waiving the ratchet mechanism, waiving the MGS cap, and applying section 7.C.7.g.[1] The Company

[1] "Unusual Loads; Line extensions to unusually small loads not consisting of a residence or permanent building (e.g. individual lights, wells, signs, etc.) will not be granted the five hundred (500) foot allowance

proposes waiving the ratchet for these customers because their consumption does not occur during summer months and exposing them to the full system costs implicit in the ratchet mechanism would be overly punitive. Applying Section 7.C.7.g insures that, the localized infrastructure costs associated directly with their significant power draw will be recovered, thus limiting the need for the higher basic service charges and preventing them from being subsidized by other customers. The Company recognizes this proposal does not fully follow traditional cost allocation of demand related costs, but believes it is a reasonable proposal for a dozen or so customers with unusual load profiles. Finally, the Company is proposing this rate only for full requirements customers because customers who net meter to zero through the summer but still draw power through the year should fully contribute their costs to the grid as they fully utilize the grid year round.

Q. Earlier you mentioned that you would provide an overview of the transition plan the Company will use to move certain SGS customers that have usage that will qualify them for the MGS or LGS rates. Will you describe the Company's plans?

A. Yes. This is an overview of what will be done, but this plan will evolve as more details of the rates become known and as more current data becomes available closer to the rate effective date.

- If the Commission approves the proposed MGS rates for certain SGS customers, the Company will promptly begin providing information about the new rates to the customers most likely to be migrated to the MGS rate.
- Educational materials detailing the new rates will be mailed (traditional and via email, if known), to customers and will be available on TEP's website and included in the Company's business customer e-newsletter.

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but will instead be required to advance any costs of service in excess of their estimated two years annual revenue. Refunding will be according to Subsections 7.C.1.c and 7.C.3.a.iv."

- SGS customers with usage sufficient to qualify them for the LGS rate (imputed demand greater than 500 kW) will be moved to the LGS rate with the first billing cycle after the rate effective date.
- SGS customers with usage meeting or exceeding 24,000 kWh in consecutive months will automatically be moved to the MGS rate on the first billing cycle after the rate effective date.
- An MGS transition rate will be created that is revenue neutral and reflects a $0.0 per kW charge on the measured kW as reflected on the bill. For this 9 month transition period a revenue neutral volumetric rate will be charged to recover the approved level of revenues allocated to this rate class.
- Once the 9 month transition period is over, the next billing cycle will reflect the final MGS rates approved in this proceeding.
- This will allow another 9 months to transpire with an actual demand charge on the bill. Staff's recommended 18 month window will allow any inadvertent impacts to be addressed if appropriate.

Q. Mr. Solganick also requested that the Company provide information on the number of customers affected by the proposed 5,000 kW cap for the LGS class.

A. The Company decided to impose the 5,000 kW cap on the LGS class to continue to move like customers to like tariffs. The LPS tariff has a billing demand minimum of 3,000 kW. Any Customer who hits 5,000 kW will have a minimum billing demand of at least 3,750 kW for the following 11 months. This 3,750 kW is above the 3,000 kW minimum billing demand for the LPS class. The Company plans to change the tariff language, to match that of MGS, so that a customer will need to hit 5,000 kW twice in twelve months before the customer is moved to the LPS rate.

The Company does not have customers in the test year that would be affected by this cap. There is one LGS-13 customer who occasionally uses more than 5,000 kW, but did not happen to do so in the test year. This customer has operated with a monthly billing demand greater than 3,000 kW for more than 3.5 years. Based on the customer's test year billing data, and only looking at the margin and fuel portion of the bill, the customer would see an annual decrease of 2.34% if the customer moved from the proposed LGS 13 tariff to the proposed LPS tariff.

E. <u>Basic Service Charges.</u>

Q. Do you have concerns with Mr. Solganick's proposed basic service charges as discussed in his Direct Testimony starting at Page 27?

A. The Company believes that modernizing rate design in a manner that allows for more appropriate recovery of fixed costs is an essential component of this rate case and that its proposed residential basic service charge of $20 per month is supported by the facts set forth in TEP's Direct Testimony. However, the Company recognizes the significant step Staff has made in acknowledging the value of incorporating the minimum system in the evaluation of the Basic Service Charge. Staff's recommendation of a residential basic service charge of $17 per month in conjunction with the elimination of the two top volumetric rate tiers is a positive step in the right direction and the Company is willing to accept Staff's recommendation. The Company has also used Staff's proposed basic service charge amounts as a guide for all classes in its revised revenue proof. The proposed values may not be exactly what Staff has proposed, but will reflect a close approximation due to some rounding. For example, Mr. Solganick proposed the basic service charge for the SGS class be set at $26.80 per month (31-4), however, the Company is proposing it be set to $27.00 per month and has used that amount in its revenue proof.

Q. Staff has suggested the Basic Service Charge for the LGS class not be changed. Is the Company willing to accept this restriction?

A. Yes, with one condition. The LGS formerly had a different basic service charge for standard and TOU tariffs. They were $775 and $950, respectively. The Company is proposing to use $950 for both customer groups. We have not made a distinction between the basic service charges in the other rate classes between a standard and TOU customer, therefore, the Company is proposing to use $950 as the basic service charge for both customer groups and has used that amount in its revenue proof.

Q. On page 36, line 19 of Mr. Solganick's testimony he has suggested the Basic Service Charge for the LPS class might be too low based on the results of the CCOSS. Would the Company like to respond to this topic?

A. Yes. Originally, the Company believed the demand charge captured enough of the fixed cost for this rate class, but after reviewing the issue as described by Staff, the Company agrees the Basic Service Charge is too low. The CCOSS indicates the charge could be as high as $17,500 per month. The Company believes substantial movement toward that number would be appropriate for this class since the impact of the increase in Basic Service Charge amounts would have a very small impact on customers of this size, plus any increase in revenues recovered through the Basic Service Charge will be taken out of the demand charges applicable to them. Therefore, the Company is proposing to increase the basic service charges for the LPS-TOU rate class to $10,000 per month as a move toward the CCOSS based charges and increase the Basic Service Charge for the 138 kV rate class to $15,000 per month because the meters and related equipment necessary to serve a customer taking service at transmission level voltage is more expensive. These proposed Basic Service Charges are still below the average cost reflected in the CCOSS, but will be a movement in the right direction. The demand charge in each of these

classes will be reduced the appropriate amount to maintain a revenue neutral shift in revenues for the class.

F. <u>Lighting class.</u>

Q. On page 37, line 22, Mr. Solganick moves on to the lighting rate class. He asks if the wattage charge being proposed by the Company in its lighting rate includes the ballast load for purposes of determining which wattage the customer will pay. What is the Company's response to his question?

A. No. The current wattage charge in the Company's lighting rate is limited to the wattage of the bulb installed. The Company believes the lighting program today under recovers its fully loaded cost. The Company's intention prior to the next case is to conduct a cost study of the current program and will have more information on LED lighting to reflect additional cost recovery in the lighting tariff.

G. <u>Residential Community Solar Program.</u>

Q. On page 3. Line 19 of Staff's witness Mr. Gray's Direct Testimony he has requested that the Company provide a detailed cost-of-service analysis and resulting rate for the Residential Community Solar ("RCS") customers. Has the Company provided this information?

A. The Company's revised CCOSS submitted in this case does provide a detailed analysis of the cost to serve a residential customer. As discussed in the Company's response to Staff's Data Request No. STF 25.8 the Company will be calculating the charge per kW associated with this RCS service to be equivalent to the final rate, including base power, for a standard residential customer approved in this proceeding. The per kW charge arrived at based on the results of this rate case will be increased by $1.00 per kW. This

slight premium in the rate reflects that customers can go solar without placing a solar facility on their property and being exposed to: potential insurance implications, roof maintenance or repair costs. In addition, TEP's proposed RCS tariff will reduce the amount of unrecovered fixed costs shifted to other non-solar DG customers.

H. <u>Lifeline rates.</u>

Q. Please summarize what the Company is proposing for the Lifeline customers?

A. In summary, the Lifeline customers should be served under any residential rate available to non-Lifeline customers, and if they meet the specified income qualifications, a standard flat dollar discount would be applied to their total bill before taxes and assessments. The Company proposed to keep the current income qualification level, which is 150% of the Federal Poverty level. The discount would be calculated once final rates are decided in this proceeding and will be designed to limit the dollar change on a typical monthly bill for the majority of the Lifeline customers to no more than the dollar increase experienced by a similarly situated non-Lifeline residential customer. The total amount of all discounts combined would equate to approximately $2.8 million annually for the various Lifeline classes (both frozen and open) and will be recovered by adding the $2.8 million to the revenue requirements of the other residential rate classes. This compares with Lifeline discounts totaling $1.8 million in the test year.

Q. Does the Company agree with Staff's recommendation as it relates to the Lifeline customers?

A. The Company agrees with Staff's recommendation to charge the standard retail rates to all customers but provide them with a flat discount if they qualify for a Lifeline discount. Once a final rate design and a final revenue requirement is arrived at, the Company would propose to recalculate its proposed flat rate discount amounts that would be

necessary to mitigate the impact to the majority of the Lifeline customers at a level that is generally the same as the dollar impact to an equivalent standard residential customer. In order to provide Lifeline customers with a discount level generally the same as they currently receive, the Company must provide discounts totaling approximately $2.8 million to support this goal. Even with this substantial subsidy, a few dozen Lifeline customers may see an impact that is slightly larger than the majority of the Lifeline customers. However, they will still receive almost $500 per year in discounts in some cases. Please see **Exhibit CAJ-R-2** for bill impacts.

In the test year, approximately $1.8 million of Lifeline discounts were allocated to other customer classes. This is the discount realized by an average of approximately 15,000 Lifeline customers during the test year. The method proposed by the Company and generally accepted by Staff will need to provide credits reaching nearly $2.8 million to keep the overall discount about the same as was realized under the rates currently in effect. This issue will be discussed further when I address the Direct Testimony submitted by ACAA witness Cynthia Zwick.

Staff's position is that Lifeline customers' rate options should be the same as all standard residential customers. This would include each of the rate components, including the basic service charge, volumetric charges, demand charges (if applicable) and riders. The Lifeline discount approved by the Commission should be applied to all rate options. The Company agrees with this position. TEP supports offering a discount to the bills of low-income customers qualifying for the program, but also sending accurate price signals. By moving to consistent rate design options for all standard customers; Lifeline customers will receive the same pricing signal as a non-Lifeline residential customer, but still receive a discount.

The Company proposes that the Lifeline discount be applied as a flat dollar reduction that limits the bill impact on Lifeline customers to an increase that is in the same general dollar amount as the standard residential customer for most of the frozen rates. Please refer to Exhibit CAJ-R-4 for a list of the 18 frozen Lifeline rates remaining and the flat discount the Company is proposing for them. All of the 5 open Lifeline rates will have a flat $15 per month discount. Although a single flat dollar reduction amount would be preferred for all Lifeline customers, bill impacts may require a different discount for certain categories of Lifeline customers. If that is the result of this proceeding, future rate cases should seek to move the different discounts to a single discount amount for all Lifeline customers. There is no cost basis for maintaining multiple levels of discounts for like situated customers just because some bills were heavily discounted as the result of rates created 25 years ago. My **Exhibit CAJ-R-2** shows the impacts of the rates on the Lifeline customer using a typical monthly amount of kWh. The monthly dollar change for a typical Lifeline customer was limited to an amount that was near a standard residential customer's monthly bill change where possible.

Q. Do you agree with Staff Witness Howard Solganick's recommendation to examine the roster of Lifeline customers on an annual basis to see who would be better off on the flat monthly discount and should be moved to the new Lifeline discount rate?

A. The Company's proposal is to put all eligible Lifeline customers on one of the standard residential rates in combination with a flat dollar discount. That discount amount will be the same for all new Lifeline customers but will vary for the Lifeline customers who qualify to stay on a frozen Lifeline rate. Those remaining on a frozen rate will still be billed on the standard residential rate but with discounts that will vary based on the frozen Lifeline rate they were formally on. This will render Mr. Solganick's recommendation moot.

I. LFCR mechanism.

Q. It does not appear that Staff agrees with many of the proposed changes the Company wishes to make to the LFCR mechanism. Would you like to address some of Staff's concerns?

A. Yes. It appears the only change proposed by the Company, relating to the LFCR, that Staff found acceptable is the elimination of the fixed charge option. No customers have participated in the fixed charge option to date and we wish to eliminate it. Staff appears to oppose the Company's other proposals to amend the LFCR.

The Company disagrees with Staff's position on the remaining changes it requested and believes Staff should reconsider this position.

Q. Why do you believe Staff is wrong as it relates to the LFCR related changes requested by the Company?

A. The most significant item opposed by Staff is the inclusion of fixed generation costs in the LFCR rates. Staff continues to mistakenly believe that by having the flexibility to adjust its purchases of energy, the Company can avoid some part of its fixed generation costs. These costs are fixed plant costs and do not vary with consumption. The Company agrees that it can adjust its "purchased" generation if sales change to lower these costs. Adjusting costs associated with "purchased" generation will automatically be reflected in the PPFAC rates and any savings (or costs) will be passed on to the customers as a revised fuel cost. The Company believes the PPFAC addresses these avoided (or additional) costs in a timely and accurate manner, but does not believe they have anything to do with the LFCR. Staff has provided no evidence or explanation as to how the Company's lost fixed costs are addressed by changes in the PPFAC, when the PPFAC

specifically excludes any non-fuel costs and the LFCR specifically excludes any fuel cost.

Adjustments in "purchased" fuel (generation capacity or otherwise) have no impact on our ability to recover fixed costs that are included in non-fuel related base rates. When rates are created, the fixed cost associated with the Company-owned generation facilities and related equipment is included in the costs allocated to the various rate classes. Those costs are then spread over an approved number of billing determinants, either demand or volumetric, depending on the class. Once in the rates, the Company must realize that level of billing determinants in all future years (until rates are reset in a future rate case) to fully recover its fixed cost. Without the Company's proposed changes to the LFCR, lost fixed costs associated with the exclusion of generation and demand costs will reduce the Company's opportunity to earn the approved level of return and will ultimately result in higher base rates for all customers in a future rate case because those costs will remain in plant and will be spread over a reduced level of sales.

The Company appreciates Staff's concern regarding the revenue impact of including generation and 100% demand charges in the LFCR, which as of the 2016 LFCR filing consisted of roughly $19.6 million which would have increased the total LFCR percentage filed in the recent 2016 LFCR filing from 1.65% to approximately 4.1%. In the intervening years, the Company does not recover these fixed generation costs—an under recovery directly caused by Commission EE and DG mandates which, by design, reduces the Company's opportunity to earn its allowed return. And since the cost of this plant item is fixed and used and useful, it will likely (in a subsequent rate case) remain in rate base and eventually result in higher base rates for all classes, including those that currently don't pay an LFCR charge. The impact of this arbitrary reduction to the amount of lost fixed costs can be quantified with a quick review of Schedule G-2 of the

Company's CCOSS. If one reduces the Operating Income on line 34 by the estimated $19.6 million quantified above and adjusted for taxes, the return on plant number on line 35 goes down by nearly two-thirds of a percentage point.

Q. Staff also opposes changing the LFCR provision that only allows recovery of 50% of the non-generation related portion of any demand charge. Why do you believe this provision inappropriately reduces the amount of lost fixed cost revenue the Company should be allowed to recover?

A. The Company believes that this is another arbitrary adjustment to reduce the amount of lost fixed costs the Company is able to recover. Not only are fixed costs recovered through the demand charge reduced by the generation component included in the demand charge, the remaining components in the demand charge are further reduced by 50%.

A simple example may help explain why this is important. Assume a demand charge is $18 per kW. If the generation component is $8, then $10 is left. The current LFCR states the company is only allowed to recover 50% of that. This leaves the LFCR recovering $5 of the $18 demand charge. For every unit of demand the customer avoids due to DG or EE, the Company initially loses $18 of fixed cost recovery, but is only able to recover $5, or 28%.

As you can see, this leaves a very small portion of the fixed costs assigned to the demand rate to be recovered in the LFCR. Additionally, this arbitrary reduction only applies to verifiable reductions to demand amounts. Specifically, those demand units identified and verified are relating to either demand based EE programs or DG demand reductions coincident with the applicable peak. These parameters already create a quantification of lost demand revenues that is very narrowly defined and limited to specifically lost demand revenues resulting from DG and EE mandated activity. Staff did not justify why

this arbitrary reduction of 50% to the lost fixed cost recoveries associated with these vary narrowly defined demand losses is appropriate. In the Company's opinion this is an unfair reduction and should be eliminated.

TEP's unadjusted test year sales in the last rate case were approximately 9,332 GWh for the 12 months ending December 31, 2011. The unadjusted test year sales in this case were approximately 9,059 GWh for the 12 months ending June 30, 2015, an approximate decrease of 2.9%. Again, even though this is more than EE and DG related reductions, this very clearly shows that during the last 3 1/2 years, sales have not increased sufficiently to offset DG or EE losses—indeed, sales have fallen, not increased. Increased sales sufficient to offset the lost fixed costs are highly unlikely.

Based on known and measurable historical data there is no reason to reduce the level of lost fixed cost identified as being related to Commission mandated DG and EE related activity. Therefore, the Company recommends that the Commission recognize these losses and add generation related losses and all demand related losses back into the LFCR rates for future recovery of lost fixed costs.

Q. Mr. Solganick also mentions the possibility of double recovering certain lost fixed costs if generation is added back to the LFCR rate and the EDR is approved. Do you agree with this proposal?

A. No. First, as mentioned above, the Company has experienced a loss in sales of over 270 GWh since the last test year. While the Company hopes this trend is not repeated between this rate case and the next, there is no indication that sales will rise in any significant amount. The rates paid by any qualifying EDR customer would be at the reduced rates specified in the EDR and would be incremental only until the next rate case at those reduced rates. As proposed, the EDR rate requires a minimum load of 3,000 kW which

means the customer would be served under the LPS rate and this class is excluded from the LFCR anyway. Even if that were not the case, if there is a concern about double recovery of generation costs, the Company would propose adding a provision to the LFCR POA that reconciled any potential over-recovery. The Company only desires to recover quantifiable lost fixed costs associated with Commission mandated DG and EE losses.

Q. Should the LFCR cap be increased from 1% to 2%?

A. Yes. If the Commission accepts the Company's other LFCR recommendations it should increase the cap. This would allow for a more timely recovery of approved costs and help prevent the allocation of those costs to later generations of customers. The cap may not be reached and if it is not, then the change will have limited impact on customers.

Q. Mr. Solganick also opposes the recovery of any lost fixed costs generated by the "Buy-Through" rate in the LFCR. Is that a concern to the Company?

A. Yes, in the event the "Buy-Through" rate is approved in a form that results in unrecovered fixed costs. If the "Buy-Through" rate is denied by the Commission or if the design of the tariff is such that the participating customers pay their full retail rate then no lost fixed cost recoveries will be necessary and there will be no need for this provision to be added to the LFCR. Staff has indicated they have no specific objection to the "Buy-Through" rate as long as no costs are shifted to other customers. As long as that statement is true and includes provisions that costs not be shifted to the Company, the provision may not be needed.

If the Commission approves any variation of the "Buy-Through" rate that results in a reduced (lost) level of fixed cost recovery, lost fixed costs should be eligible for recovery. The Company would consider other proposals, but the Lost Fixed Cost Recovery

mechanism seems to be the most appropriate method to recover any losses. But as I discuss later in this Rebuttal Testimony, the Buy Through tariff should simply be rejected.

Q. Will these changes require a revised POA be submitted once the details of these rate design and LFCR issues are resolved?

A. Yes. The Company has proposed a revised LFCR POA reflecting its proposed changes, but any modification to the Company's original proposal could require further revisions to the POA which might include language to address any potential transition rates versus the final rates as separate calculations in future LFCR filings. The revised POA could be submitted with the Company's compliance filing that will be submitted at the conclusion of this proceeding.

J. <u>Prepaid rate issues.</u>

Q. Do you wish to address any issues expressed by Staff witness Connolly?

A. Yes. Mr. Connolly primarily addresses the Company's proposed Prepay program and the compliance issues the Company submitted various changes to. Most of the Prepay issues will be addressed by the Company's witness Ms. Smith. However, I will address his concerns relating to the rates proposed by the Company and his request to include Lifeline customers in the program.

Q. Please continue with your rebuttal of Mr. Connolly.

A. Yes. I wish to respond to his suggestion that the Prepay rate include a provision that allows Lifeline customers to participate and still benefit from the discount they have available to them under the standard tariffs. The Company agrees to add a provision to the tariff that would make the rate available to Lifeline customers if they qualify under

the standard tariff. They would benefit from a discount to the daily fixed charge that would be based on the final fixed discount available to new customers divided by 30 days in an average month. This would give them the same benefit as a standard Lifeline customer would enjoy. These Prepay rates are designed to be revenue neutral for a standard residential customer, therefore the rates will be updated to reflect that same revenue neutral calculation based on the final rate approved in this proceeding. It is not the Company's intention to create a discounted rate and the only incremental charges applied to this service were fully described in my Direct Testimony. The additional charges are limited to the additional $2 for the cell phone needed to provide two-way communication, an additional $1 per month to cover the incremental cost of the meter used to serve these customers and a $2 per month contribution toward the software cost necessary to provide this service.

Q. Do you agree with Staff Witness Matt Connolly's recommendation not to charge a Service Establishment Fee to activate a Prepay account?

A. No. All customers are charged a Service Establishment Fee (refer to the Arizona Administrative Code R14-2-203.D.1). The cost to establish service for these customers will be no less than for any other customer.

K. <u>Environmental Cost Adjustor.</u>

Q. Do you wish to address any issues expressed by Staff witness Van Epps?

A. Yes. Mr. Van Epps' testimony is primarily expressing a request for either additional or modified Plan(s) of Administration for the DSM, REST and Environmental Cost Adjustor ("ECA"). Company witnesses Ms. Smith and Mr. Tilghman will address the issues with submitting the DSM and REST POAs as part of this proceeding. I will discuss the ECA POA below.

Staff's request relating to the ECA POA is designed to clarify and document changes already discussed by Staff and the Company. The Company does not object to the changes and will work with Staff to update the ECA POA and submit it to the Commission for approval prior to the conclusion of this proceeding. The only issue outstanding relates to the Company's request to apply the ECA rate on a percentage basis. The Company still believes the charges should be based on a percentage adjustment instead of the current $ per kWh adjustment. The Company will submit its final POA based on whatever final decision the Commission makes on this topic.

L. <u>Miscellaneous issues.</u>

Q. Do you agree with Mr. Solganick's recommendations as it relates to how distributed generation customers should be addressed as the result of this proceeding as discussed starting on Page 40 of his Direct Testimony?

A. While some of his statements are consistent with the Company's position as it relates to the partial requirements customers using distributed generation, there is no clear recommendation on how to address the growing issue of costs being shifted from those who can benefit from the antiquated net metering rules to the full requirement customers.

The Company believes its recommendations make a movement in the right direction although they do not address the issue fully. Staff seems to prefer "kicking the can down the road" and suggests waiting on the resolution of two other pending dockets. The Company withdrew an application[2] that addressed these issues because some of the

[2] On March 25, 2015, TEP filed an application with the Commission (Docket No. E-01933A-15-0100) requesting changes to its net metering tariff. TEP subsequently withdrew its application on June 19, 2015 with the intent of seeking net metering modifications in this rate case docket.

parties to this rate proceeding wanted the issues addressed in a rate case. We are now in a rate case. And now is the time to start moving in the right direction. As the cost studies filed in Dr. Overcast's Rebuttal Testimony demonstrate the level of subsidy is much too large to continue to postpone the proposed changes in the rates applied to solar DG.

Q. Do you accept Mr. Solganick's recommendations as it relates to the Service Fee Charges discussed on Pages 46 and 47 and the AMI Opt-out charge discussed on page 48 and 49 of his Direct Testimony?

A. Yes. We will work with Staff to finalize the specific wording necessary to convey the recommendations made, including language to modify how we will charge for requests from the MGS rate classes for interval data during the transition period while customers are trying to figure out how the new three-part rates will be affecting them.

Q. On page 37, Mr. Solganick requested additional information in support of the Company's proposed 138 kV rate. Will you provide that information at this time?

A. Yes. His first concern was with the proposed basic service charge. The Company has addressed that issue earlier in my testimony. The one customer eligible for the service was formally a Rate 90 customer with multiple meters "grandfathered" into a totalized account. Since this class was to be specifically for 138 kV service, the Company's original position was to separate the meters into their appropriate rate classes and add their billing determinants to the appropriate class accordingly. With the public notice of reduced load the Company has made some modifications to its CCOSS as it relates to the 138 kV rate. We re-totalized the customer's accounts and left the respective billing determinants in the 138 kV rate. This also required the Company to add additional Distribution costs to the rate class due to a portion of the load for this customer being served at less than a 138 kV level of service. The new rates proposed in this rebuttal testimony reflect these revisions. Additionally, the original draft tariff will need to be

modified to incorporate language that specifically limits the inclusion of load served at less than 138 kV to only "grandfathered" loads.

Q. Mr. Solganick on page 32, line 10, has requested the Company provide additional information relating to the proposed tiered demand charges being proposed in the residential and SGS demand rates. Will the Company be providing that additional explanation?

A. Yes. The Company's witness, Mr. Bachmeier, will be providing additional information in response to Mr. Solganick's request.

Q. Do you agree with Staff Witness Eric Van Epps's recommendation that TEP reassess its Demand Side Management (DSM) adjuster in TEP's next DSM Plan so that all customers, both residential and non-residential are billed based on an energy-based charge?

A. No. This format was approved because the largest customers were paying a proportionally larger part of their bill toward the DSM recovery under the dollar per kWh method. At the time the percentage based adjustment was established for all non-residential rate classes, all parties agreed to the modification and believed it was in the best interest of the parties as a whole. To change the process back will increase the burden on the larger rate classes in a disproportionate manner. I have created an example below that develops a DSM charge based on the total retail revenues, and total kWh sales proposed in this Rebuttal Testimony and the DSM revenue level that was used in the Company's direct rate case. Based on this data the DSM rate for all rate classes as a percentage would have been 1.8930% and the dollar per kWh rate would have been $0.002121 per kWh. Using this information in the table below allows one to see the impact of the two methods of cost recovery on three different sizes of customers. It shows how the dollar per kWh method shifts substantial costs to the larger customers.

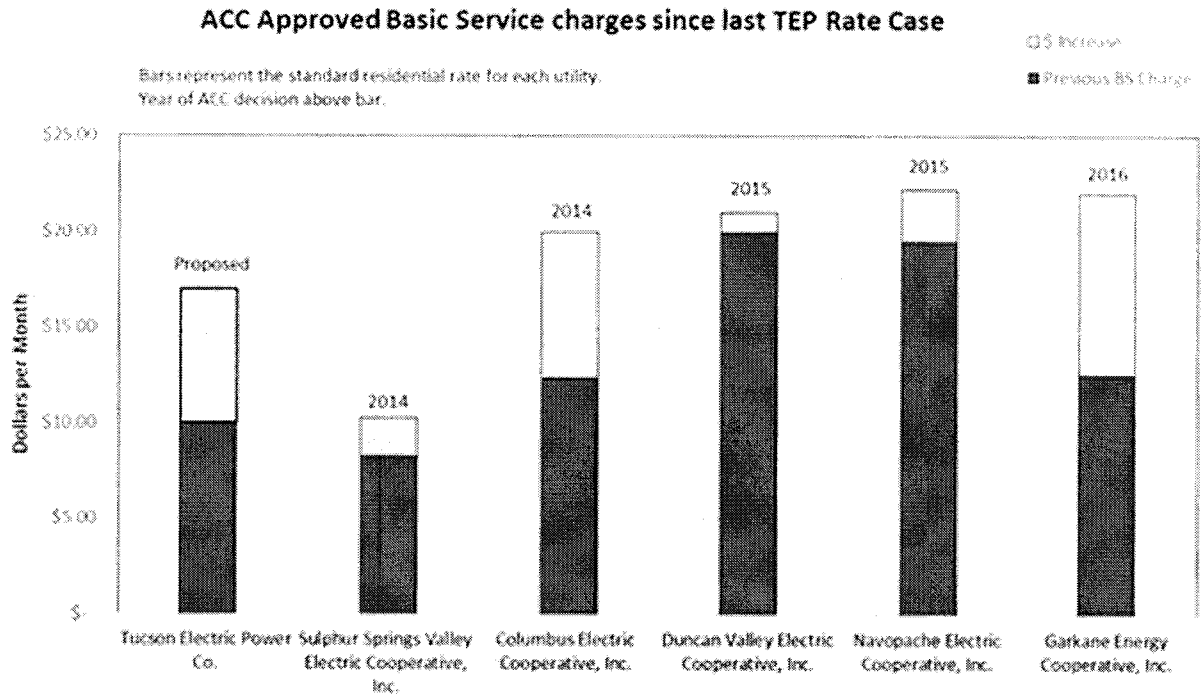
			Per-kWh DSM Rate		Percentage DSM Rate	
Customer	Billed kWh	Bill Amount	DSM Charge	% of Bill	DSM Charge	% of Bill
MGS	24,544	$ 3,649.24	$ 52.06	1.4%	$ 69.08	1.9%
LGS	178,619	$ 19,089.91	$ 378.85	1.9%	$ 361.37	1.9%
LPS	6,174,912	$457,828.39	$ 13,096.99	2.8%	$ 8,666.69	1.9%

V. RESPONSE TO RUCO.

Q. What concerns does the Company have with the positions expressed by RUCO witness Mr. Huber?

A. The primary concern the Company has with Mr. Huber's recommendations relates to his objection to increasing the basic service charge. The Company dedicated a substantial amount of its Direct Testimony to explaining and supporting its proposed basic service charge. The Company's CCOSS supported a greater charge. RUCO recommended no change to the basic service charges and totally ignores the true cost to serve a customer as is shown by the use of the minimum system approach, which is fully discussed and justified in the Rebuttal Testimony of the Company witness Dr. Overcast. The data supports more than the $17 monthly charge for the residential class proposed by Staff. In the spirit of compromise, the Company is willing to accept the $17 residential basic service charge as proposed by Staff. Dr. Overcast discusses the data and methodology supporting an increased basic service charge in more depth.

Additionally, Mr. Huber indicates he believes basic service charges for other utilities are not trending upward. The following table includes changes made since the last TEP rate effective date to basic service charge for residential customers of Arizona utilities. Please see the attached table for a summary of our findings:



Q. Various Intervenors claim that increasing the fixed charge or reducing the number of tiers, and thus reducing the highest block rate, will lead customers to use more power. How is this characterization incorrect?

A. Mr. Huber at page 9, line 2, regarding basic service fees states; "Fifth, the proposal reduces the incentive for customers to conserve energy." This argument, like ones made by others that I address later in my testimony, ignores the basic fact that based on the Company's rate design proposals, as customers use more energy, their electricity bill will increase thus sending a very clear price signal to conserve energy. The existing inclining block rates provide a very murky price signal as many customers are unaware of them in the first place and do not currently know when they cross a tier threshold. Customers also seem to have difficulty understanding inclining block rates. Mr. Huber has not provided any support or a study that might indicate a customer has any knowledge as to when they might move from tier 1 to tier 2 to tier 3 to tier 4. Based on feedback received at our call center and my personal experience as a rate design expert in the electric industry for over

30 years, customers just don't like or understand tiered rates. Like other customers, I typically have no idea when I move from one tier to the next (unless I go out and read my meter every morning and note the read and do the math). But I know my bill is higher when it is hot. I know my bill is higher if I use a welder, grinder or a hammer drill for too many evenings in a row. I know if my kids are staring into the refrigerator, leaving lights on when they leave the room or if I take a long hot shower with an electric water heater my bill will increase. I know a lot about my total bill that might drive my conservation habits, but the fact that there are 4 tiers has nothing to do with that knowledge. In fact, we receive many complaints from our customers trying to figure out why their electric bill is higher and we have to explain they moved into a more expensive rate tier. Trying to explain to a customer that the more they use causes an increased per unit charge is not something they understand. Tiered rates have no bearing on what the customer's usage habit is. The total bill does. I also note that Dr. Overcast has addressed this point in his Rebuttal Testimony and has discussed a recent economic study that reaches this same conclusion based on a university study.

Q. What is the Company's position on RUCO's proposals to maintain three inverted block rates for the residential rate class?

A. While the Company appreciates RUCO's willingness to eliminate the fourth rate tier, the Company does not understand RUCO's reluctance to eliminate the third tier as well. RUCO's unfounded argument for inverted block rates simply has no merit. This position is simply wrong and the Company firmly believes two tiers are the most that should be reflected in the residential customer's rate design. Ideally, there should be no tiers at all. Too many tiers simply adds further cross-subsidies to the rate structure.

Q. Various intervenors make an analogy between the electric utility industry and the gasoline industry to argue that fixed costs should be collected through volumetric fees. How best can these analogies be characterized?

A. These analogies can best be characterized as weak and fundamentally flawed. Mr. Huber on page 9, line 18, refers to the gasoline industry as one that recovers fixed cost on a volumetric basis. The gasoline industry, and all those listed by other Intervenors, are completely different businesses from an electric utility. Although not an exhaustive list of differences, the following are some of the most pertinent. Gas stations are not price regulated (nor have I ever seen a tiered price for gasoline). They are free to serve only the most profitable areas and are not forced to differentiate prices based on classes of customers. They are not required to venture to their customers' homes to provide their service. Gasoline can be stored to buffer customer demand. Gas stations can change prices on a real time basis in response on current market conditions that are not subject to review. They do not have to be prepared to meet all of their customers' demand at the same time. Further, gas stations have relatively low fixed costs compared to electric utilities, making an all-volumetric approach far more feasible. A far closer analogy is the fuel component of the PPFAC, which is purely volumetric just like retail gasoline sales.

Q. Mr. Huber included a table on page 26 that he uses in his discussions. Do you believe the table accurately reflects the impacts of the Company's rate proposals?

A. No. The table fails to recognize a customer's bill includes fuel costs that are charged on a per-kWh basis. Ignoring the per-kWh cost of fuel simply misrepresents the facts. Also, bills with usage in the highest tiers still include kWh priced at the lower tier rates. As you can see in the corrected versions of the table I have included below, using annual bills and the full cost of the energy purchased by the customer, the Company's proposed rates do not produce a decrease in the average volumetric rate for any of the tier groups, in either the Direct or Rebuttal proposals. In fact, based on the Company's direct position, it

would take usage greater than 4,472 kWh during a summer month before a customer would see a decrease in the volumetric portion of their bill. Only 0.3% of the summer bills during the test year reached this usage level, not the 41% he indicates on line 14. Under the Company's Rebuttal position, only 0.03% of summer and winter test year bills would see decreases to the volumetric portion of their bill compared to current rates.

Table 1: Volumetric Rate Comparison: Direct Position to Current for Standard Residential

Usage Range	Existing Average Delivery Rate	Existing Average Fuel Rate*	Total Existing Average Rate	Proposed Average Delivery Rate	Proposed Average Fuel Rate	Total Proposed Average Rate	Dollar Change per kWh	% Change per kWh	% of Bills, Annually
0-500	0.0562	0.0340	0.0902	0.0591	0.0348	0.0939	0.0037	4.05%	41.0%
501-1000	0.0592	0.0345	0.0937	0.0652	0.0352	0.1004	0.0067	7.19%	32.1%
1001-3500	0.0680	0.0356	0.1036	0.0728	0.0363	0.1091	0.0055	5.32%	26.3%
>3500	0.0774	0.0360	0.1134	0.0769	0.0368	0.1136	0.0002	0.20%	0.6%

* Includes PPFAC effective May 1, 2016 for $0.001501/kWh

Table 2: Volumetric Rate Comparison: Rebuttal Position to Current for Standard Residential

Usage Range	Existing Average Delivery Rate	Existing Average Fuel Rate*	Total Existing Average Rate	Proposed Average Delivery Rate	Proposed Average Fuel Rate	Total Proposed Average Rate	Dollar Change per kWh	% Change per kWh	% of Bills, Annually
0-500	0.0562	0.0340	0.0902	0.0612	0.0334	0.0946	0.0044	4.87%	41.0%
501-1000	0.0592	0.0345	0.0937	0.0678	0.0339	0.1017	0.0080	8.59%	32.1%
1001-3500	0.0680	0.0356	0.1036	0.0761	0.0349	0.1111	0.0075	7.24%	26.3%
>3500	0.0774	0.0360	0.1134	0.0806	0.0353	0.1160	0.0026	2.27%	0.6%

* Includes PPFAC effective May 1, 2016 for $0.001501/kWh

Q. On page 28 Mr. Huber suggests that all customers with annual usage averaging 950 kWh per month be automatically moved to a new RUCO-proposed TOU rate with a shorter on peak period that differs between the summer and the winter. What is the Company's opinion on this recommendation?

A. There are a few things the Company believes need to be addressed if a proposal like this is going to be offered.

- The Company questions the value of a default rate. The Company would expect that the first month the customer notices their bill is higher because of on-peak consumption, they will call, log a complaint, and request that they be changed back to the standard rate. Creating a system to identify these customers and track them would add administrative burden and cost and potentially increase complaints.
- 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.
- It is essential that all TOU rates have the same non-fuel rates and that the tiers are identical to the equivalent non-TOU rate. Of course the Company prefers only two tiers. Any differential in on-peak and off-peak rates should be in the fuel costs. The primary cost differences are higher purchased power and fuel cost associated with less efficient resources and market cost. Therefore the Company is of the opinion that any differential should be in fuel and not in the non-fuel costs. Additionally, the Company provided a study in its last rate case that supported the current on- an off-peak periods. Mr. Huber has provided no such analysis in support of the change in on- and off-peak periods he has proposed.

Q. What is the Company's position on RUCO's proposals for DG related rates?

A. RUCO has suggested a variety of options for DG customers, including a demand based rate, a buy-all sell-all rate with a declining renewable credit rate, a standard volumetric TOU rate, and a provision that allows a customer to choose any non-demand based rate with a $/kW or MCCCG credit applicable. All options have an incremental meter charge to help recover the cost of the additional meter required to serve the DG customer.

The Company appreciates the spirited approach Mr. Huber is taking when creating proposals to address the cost shift issue that exists as the result of the current net metering

rules and the Company's antiquated rate design. The Company is of the opinion that the only way to address the cost shift issue associated with the current net metering situation is some form of mandatory demand rate applicable to these partial requirement customers. Since net metered customers are only billed for their net consumption over the course of a year, historically they are charged, on average, for about 30-40% of the energy compared with a full requirements customer (this includes early adopters, new installations are even less and may experience a 100% offset of their consumption). This banking and netting results in an under recovery of costs from the partial requirements customer. Further, over fifty percent of the bills for these customers have zero kWh so any reasonable cost recovery must include some other charges to recover fixed costs.

Many of the components in RUCO's suggestions would help address the cost shift. The Company agrees that an incremental meter charge would be appropriate for DG customers in that they need additional metering to track solar production. Currently the costs of these incremental meters are shifted to all other customers through the REST. The Company does agree that some form of demand charge based on a customer's capacity usage, a DG system size based $/kW charge or even MCCCG based credits for excess production would also help address the cost shift. However, allowing monthly netting of excess production does not move far enough to help mitigate any significant portion of the cost shift. As discussed in Mr. Dukes' Direct Testimony submitted on behalf of the Company, most new systems have very little if any[3] billed usage with the application of the net metering tariff (55% of all R-01 net metering bills during the test year were for zero kWh and almost 75% of the bills were for usage of less than 400 kWh). Current annual banking provided for in the net metering rules prevents any substantial contribution to the cost necessary to serve these customers' needs. Monthly

[3] In fact, as of the writing of this testimony a review of the most recent 50 DG installations was made and the percentage of annual usage covered by the DG system was 98% for the group.

banking (as opposed to annual banking, which is currently in place) provides only a nominal increase in cost recovery. The DG customer still avoids almost 90% of the fixed costs to serve the customer. Therefore, the Company believes its recommended mandatory three-part standard and TOU rates with no banking is the superior rate for all new net metering customers and allows for movement toward more appropriate levels of cost recovery. It is a cost based and cost effective proposal. The Company's proposals are simply a step in the right direction. They do not resolve the cost shift issue, but move in that direction.

As proposed, none of RUCO's options adequately address the cost shifts associated with net metering especially when combined with monthly banking. However, a number of RUCO's proposals could be modified to recover a greater portion of the fixed system costs necessary to serve net metering customers. The Company is concerned that the multiple options may become confusing and a challenge for customers to understand. Mr. Huber references one of Mr. Bonbright's rate design principles of simplicity on page 5, line 19 of his testimony. I do not consider RUCO's proposals as being simple.

Q. Would you like to comment on other RUCO witness' testimony in this proceeding?

A. Yes. While I have addressed why I believe the Company's proposed basic service charges, as modified to reflect Staff's recommendation, are appropriate elsewhere in my testimony and explained why only two tiers are appropriate for residential rates, I do have a couple of specific issues with Mr. Radigan's testimony I wish to discuss and one issue with Mr. Michlik's testimony. These topics include weather normalization and frozen Lifeline rates.

Q. Both Mr. Michlik's and Mr. Radigan's Direct Testimonies took the stance that it was problematic that the Company would not run models with weather averages based on different periods of times (anywhere 8 year averages to 30 year averages). RUCO insists they cannot evaluate how well the model fits the data or how robust the model is without these different model runs. How does the Company characterize this evaluation?

A. In reviewing Mr. Radigan's discussion on why the Company's weather normalization calculations were not acceptable to him, it is clear that he did not take the time to familiarize himself with the Company's weather normalization model, and therefore does not understand the model. An extensive explanation of the Company's statistical model, inputs and related data was provided in responses to data requests to both RUCO and Staff.[4]

The Company's weather normalization and modeling process is summarized below.

The Company uses an ARIMAX model. The Company explains this type of model in great detail in the document filed in response to data request Staff 1.06, and referenced in RUCO 3.12 and RUCO 7.05. An important aspect of this model is the exogenous inputs. This is standard regression analysis where independent variables (weather and economic) are used to predict dependent variables (Use per Customer, or "UPC"). Average weather is not an independent variable in the model and thus it has exactly zero bearing on the weather coefficients, the robustness, or the accuracy of the model. To re-phrase this, the Company takes its *historical* monthly UPC data and *historical* weather data from the National Weather Service and feeds this into the model. The Company used its full range of recorded, historical UPC for the model fitting part and has actual, calculated average hourly temperatures for each corresponding month in that historical range. It would be an

[4] TEP's Responses to Data Requests Staff 1.06, RUCO 3.12, 7.02, 7.03 and 7.05.

unsound statistical practice to shorten this range, and impossible to lengthen it (again, because it is actual historical data). It is this model fitting period that determines the coefficients that will eventually be applied to normal weather for weather normalization purposes. As answered in RUCO 7.02, the range of historical data for fitting purposes for this model was January 1993 through June 2014.

The second step in the modeling process is to apply the coefficients produced in the fitting step to "normal" weather values to determine the weather normalized UPC for the test year (July 2014 – June 2015). This is where the Company used the 10-year average. The Company has defined average weather in its previous rate cases using the 10-year average. Additional reasons for choosing a 10-year average are the relative stability of the 10-year average compared to shorter time lengths, and the consistent warming trend that relegates longer time lengths unreflective of recent weather patterns. If RUCO desires to use another definition of "normal", all they would need to do is calculate "normal" temperatures using their definition. Once these are obtained, they would just need to apply the appropriate coefficients, determined in the model fitting section, to these weather values to obtain a weather normalized UPC forecast consistent with the equation supplied in response to RUCO 7.05. To reiterate, the coefficients do not change depending on the type of average use. They were established using historical information. RUCO has been provided the data, in RUCO 7.03, to calculate different "normal" scenarios if they please. These different values will not give any sense of the "robustness" of the model as they do not determine the model selection or the coefficients produced by the model.

As such, Mr. Radigan's statement on page 30, line 16, that it was "impossible to test the robustness or true accuracy of the model" because the Company did not run the model with different time periods for average weather is false. The Company provided results of

ample testing of various models and provided a complete set of model statistics in RUCO 7.03 which could actually be used to test model fit. Those documents make it entirely clear that the Company's model fits the data better than the other models available and that it is a highly robust model.

Finally, the Company believes Mr. Radigan should provide more reasoned justification for using a different definition of "normal". It is an unsound statistical practice to choose the variables to achieve a preferred outcome. The Company never considers the results of its weather normalization process when selecting how to define average weather as Mr. Radigan is suggesting it should. Again, this is poor statistical practice and the Company is astounded that such a method is being suggested as reasonable modeling practice. A model should never be chosen because it provides a result that one deems more favorable, but should instead be chosen on how well it models the dependent variable on a broad range of statistical measures. It is this latter method that the Company uses when determining the best model. In responses to data requests, RUCO witnesses Radigan and Michlik continued to advocate for this statistically corrupt method making it clear they have not developed a full understanding of the Company's weather normalization model.

Q. Mr. Radigan states on page 30 of his Revenue Requirement Direct Testimony that it is troubling the Company does not track vacant homes or the number of seasonal customers. Do you agree?

A. No. Most seasonal customers, whether they are snow birds or students, tend to be in Tucson the same time every year. As such, the model will pick up and account for their presence when looking at historical data. The ability of the ARIMAX model to pick up on non-weather related seasonal trends is one of the strengths of the model. As explained in the document referred to in the Company's responses to data requests RUCO 3.12 and RUCO 7.05, on page 14:

> By combining the power of both of these models, the effects of weather and economic trends can be isolated from non-weather related seasonal patterns. This produces a truly robust set of weather coefficients that greatly increases the reliability of the weather normalization compared to pure regression coefficients. TEP's service territory is subject to seasonal trends that happen independently of weather but would otherwise be rolled into monthly weather coefficients. For example, the student population at the University of Arizona swells significantly each August when students move in and diminishes each May when students move out. This occurs every year at the same time of year but is wholly unrelated to weather. An ARIMAX model accounts for these types of changes better than a plain ARIMA model and, in this case, the additional complexity is worth the decrease in parsimony.

As such, knowledge of the number of seasonal customers is not necessary for the modeling process as the model used by the Company already accounts for these processes and isolates them from the weather.

The tracking of vacant homes that Mr. Radigan deems vitally important would not add any significant information to the model and has no real cost justification. The Postal Service does track these numbers and the Company has looked into using these numbers in its regression analysis. As discussed below, the results of that analysis show that the vacancy rate is insignificant[5] and thus unnecessary for the Company to track and should not be included in the Company's weather model.

[5] http://www.census.gov/housing/hvs/files/currenthvspress.pdf .

Q. Mr. Radigan, on page 31 of his Revenue Requirement Direct Testimony, states that the "Other Change" category "moves up or down seemingly in a random pattern". Do you agree?

A. No. In response to company data request TEP 2.7, Mr. Radigan admitted no study was done to determine the change was random and that his determination was "evidenced by a casual observation". Classifying a variable as random requires careful statistical study and Mr. Radigan's casual observation lacks the necessary rigor to justify such statements. Far from being random, the "Other Change" category looks to mirror the overall Tucson economy well and the Company believes that, even though it can't say exactly what percentage is due to the economy, most of the change is from economic drivers. In the years 2008-2010, the "Y/Y Other Change" is negative aligning well with the housing market collapse. In 2011 and 2012, the economy started to regain some ground until 2013 and 2014 when federal fiscal drag related to the sequester and federal government shutdown negatively impacted the region. Southern Arizona and the Tucson economy are disproportionately reliant on federal government expenditures due to major employers like Homeland Security and Air Force, as well as research grants awarded to the University of Arizona. In 2015, with the federal fiscal drag waning, the Tucson economy began to grow steadily and did quite well in the last quarter of the year. In short, the change wasn't random.

In response to TEP's data request to RUCO, number TEP 2.8, Mr. Radigan claims to have reviewed economic data online regarding Tucson's economy, but it is clear from his analysis of the other change category that he did not absorb or understand the data he reviewed. Further, in response to TEP 2.7, Mr. Radigan claims that the year-over-year change in the "Other Change" category's relative magnitude is relevant to the change in the weather category. This continued insistence shows that Mr. Radigan does not understand the weather normalization process. The difference of 154 kWh he mentions is

the difference between the weather normalized UPC, and as such there is no change due to weather in this 154 kWh. That is to say, this 154 kWh is the change in UPC due to anything BUT weather. The remaining difference between the non-weather normalized UPCs, 353 kWh, is the change in UPC due to weather and is of a greater magnitude than the 144 kWh of the 154 kWh that has been attributed to the "Other Change" category. Further, he fails to realize that the year-over-year change in sales due to weather is irrelevant to the total sales due to weather. If two consecutive years had exceptionally warm summer weather, both years would have greater sales than normal but the year-over-year change would be very small and thus unreflective of either year's actual weather related sales

Q. Does the Company accept that only ½ of the proposed adjustment for weather be allowed?

A. No. The Company provided significant analysis to the validity of its adjustment and, as the previous testimony has made clear, Mr. Radigan made incorrect arguments to either reduce the weather adjustment by half or to completely remove it. Further, this exact same model was accepted in the UNS Electric rate case. The only difference being it resulted in a positive change to UNS Electric's test year revenue and a negative change to TEP's. The direction of a change, when based on sound statistical analysis, is not a valid basis to reject an adjustment. In response to the TEP 2.9, Mr. Radigan admitted that he performed no analysis in deriving his ½ adjustment thus making his claim indefensible.

Q. Mr. Michlik states that it is a problem that the Company does not break out the revenue adjustment based on the weather normalization and customer annualization adjustments. Does the Company agree with this assessment?

A. Not only does the Company not agree with this assessment, the Company does not see "because the categories cannot be separate" (Michlik, page 14, lines 5-6) as a valid

explanation for this being a problem. The Company provided a breakout of the sales adjustment by unbilled, weather normalization, and customer annualization. Due to the complexity of the tiered rates, TOU rates, and the number of rate schedules, it is no small undertaking to determine a meaningful split of the revenue adjustment. If RUCO would like to see how the rates were applied to the adjusted numbers, and to check these calculations, they may look at "Rate Case 2015 TEP Normalized Revenue and Sales Public Version" in the TEP rate case data room.

Q. How would the Company describe RUCO's proposal that it should file an annual report of weather normalized sales and revenues?

A. Other than making the claim that it should be done, RUCO failed to support why the Company and its customers should be burdened with the additional administrative costs with performing the extensive weather normalization process on an annual basis. RUCO failed to detail how it would be beneficial to any of the interested parties as the report would have limited value. In response to a Company data request TEP 2.16, RUCO admitted that it did not perform an analysis to show that this requirement is in the ratepayer's best interest. Further, RUCO claimed that the process would not be burdensome making it evident they did not review the extensive work papers and analyses the Company provided in support of its weather normalization process which show that such a requirement is a significant burden. This invalidates RUCO's claim that the Company did not provide sufficient evidence to support its weather normalization adjustment because it is clear they did not review or did not understand the Company's weather normalization process and are simply objecting to it on baseless grounds. Finally, when asked what other utilities have to provide such annual reports, RUCO pointed to Southwest Gas Corporation. The Company agrees that it is in the ratepayer's best interest for Southwest Gas Corporation to file an annual report as they have full revenue decoupling. As the Company does not have full revenue decoupling, and is not proposing

full revenue decoupling, no reason exists for the Company to file such reports. The Company already goes through an extensive IRP process every two years, which the Company feels more than adequately looks at sales historically and in the future. For these reasons above, the proposal of filing annual weather normalization reports should be rejected.

Q. Please explain your concern with Mr. Radigan's recommendation as it relates to the Lifeline customers.

A. The Company is proposing to place all Lifeline customers on a standard residential rate and apply a flat discount to the individual customer's monthly bill that is sufficient to minimize that customer's monthly bill impact. This would create 5 open Lifeline rates. There are also 18 different Lifeline rate classifications that are frozen and not open to new customers. Some of these rates were created over 25 years ago and have not kept up with more modern rate design theory. Both frozen and open Lifeline customers will be billed based on their equivalent non-Lifeline rate. This will allow for a more equitable application of rates to all customers. As mentioned in my Direct Testimony and acknowledged by Mr. Radigan, there are 11 of the 18 frozen Lifeline rates that have less than 20 customers on them, and two rates with a single customer.

Mr. Radigan seems to make light of our request to eliminate some of these rates by saying on Page 11, line 1 in his rate design testimony, "...why even bother going to so much effort for so few." In reality, maintaining a frozen rate for a small number of customers is costly and burdensome. Any time there is a rate, whether it is for one customer or 100,000, the class is tracked for reporting purposes, it must be built into the billing system, it must be included on every report, customer service personnel must be trained to respond to questions, the customer's eligibility must be tracked, and any bill change must be tested and reviewed. This all takes a great deal of time and effort.

Mr. Radigan then goes on to say on line 3 of that same page, "...I can find no evidence that it has proposed a pro-forma adjustment to share that savings with customers." Again, a lack of understanding that as a utility, we continually try to identify areas that can be streamlined in a way that will eventually allow for more productive use of employees' time and our customer's dollars. This is a transitional event that will do just that. As these activities are addressed and eliminated it will allow for existing personnel and billing systems to operate in a more efficient manner and allow for incremental improvements in their ability to serve the remaining customers. As we identify areas where improvements can be made, the Company pushes to address them in a pending rate case where possible. In the long run, eliminating inefficient duties benefits the entire system. Having to build and test a billing system to address a rate with one customer on it is one of those areas a responsible utility should ask to be addressed and a representative of the party tasked with representing the residential customers should address with something more than a light-hearted disregard.

VI. RESPONSE TO AECC.

Q. AECC witness Mr. Higgins offered both support for certain Company proposals and a couple of concerns. Do you wish to address those concerns?

A. Yes. Mr. Higgins was generally supportive of the Company's use of the 4 CP – Average & Excess Demand ("4CP AED") method to allocate production demand and transmission cost to the rate classes, but he did not like the level of subsidy shown by the CCOSS for the larger rate classes. He believes the Company's revenue allocation between the rate classes left too many inter-class subsidies unaddressed. He also suggested that a few modifications be made to the filed CCOSS. The Company made corrections to a couple of areas Mr. Higgins questioned through data requests and the Company agrees with Mr.

Higgins' allocation of A&G expenses addressed in his Direct Testimony. He pointed out a few other items where he had a difference of opinion from the Company, however, the Company does not agree with those suggestions.

As it relates to Mr. Higgins' suggested changes to the revenue allocations between the rate classes, the Company does understand his recommendations and intends to move in the direction he suggests in future rates cases if supported by future CCOSSs. For this proceeding, the Company has chosen to adjust the revenue requirement allocation between the rate classes in a manner more reflective of Staff's proposal as shown in **Exhibit CAJ-R-3**. While the final revenue allocation proposed by the Company does not add the level of cost to the largest rate classes suggested by Staff, it does move further in that direction than what TEP originally proposed. The Company believes the allocation proposed in its Rebuttal Testimony is a fair compromise. More movement is warranted and if the CCOSS results in future rate cases supports it, we will continue to make proposals that will reduce this subsidy.

Q. Do you wish to address Mr. Higgins suggestions relating to the Buy-Through rate?

A. Not at this time. More than one Intervenor has offered thoughts on the Buy-Through rates, therefore, I have addressed it later in my testimony as a separate topic.

Q. On page 43 Mr. Higgins indicates he does not believe the Company calculated its unbundled rate correctly. Do you have any comments?

A. Yes. Mr. Higgins would like to see more generation costs assigned to the generation component of the unbundled rates. The Company agrees some additional cost could be moved to that cost component, but does not agree Mr. Higgins has done it appropriately. At the very least, the fixed must run costs and some of the other ancillary costs should remain in the Distribution component because they are needed to maintain stability of the

system. The Company chose to allocate more cost to the Distribution component than Mr. Higgins did. There is likely some middle ground on a portion of these costs, but it is not the proportion suggested by Mr. Higgins. The Company would be willing to discuss this further, however for the LPS class there would be no impact on their bill unless the Buy-Through rate, which TEP opposes, is approved.

Q. Mr. Higgins believes that master-metered mobile home parks that have not historically been served on the GS-M-F rate should be allowed to take service under this tariff. Does the Company agree?

A. No. The Company is of the opinion the following rule is very clear:

> **R14-2-205. Master Metering**
> **A.** Mobile home parks -- new construction/expansion
> 1. A utility shall refuse service to all new construction or expansion of existing permanent residential mobile home parks unless the construction or expansion is individually metered by the utility. Line extensions and service connections to serve such expansion shall be governed by the line extension and service connection tariff of the appropriate utility.
> 2. Permanent residential mobile home parks for the purpose of this rule shall mean mobile home parks where, in the opinion of the utility, the average length of stay for an occupant is a minimum of six months.
> 3. For the purpose of this rule, expansion means the acquisition of additional real property for permanent residential spaces in excess of that existing at the effective date of this rule.

Any Mobile home park attempting to move to the rate would not qualify primarily because the rate is frozen which means no new premise could be added to the class.

Q. Mr. Higgins states that if the average rates charged to master-metered mobile home parks are greater than the rates charged to residential customers, then the mobile home park operator is unfairly harmed (page 49, 6-10). He also believes it is "not reasonable for a customer who must resell its power at residential rates" to have a demand charge (page 49, 20-22). Does the Company agree?

A. No, the Company does not agree. Currently, master metered facilities that feel they are burdened by the Arizona Administrative Code, or the Company's rates, can allow TEP to

individually meter their customers under standard residential rates subject to the line extension policies. This both prevents individual tenants and the park owners from being unduly harmed and is in line with the current codes which do not allow for master metered facilities.

Q. Mr. Higgins insists that his hypothetical master-metered mobile home park, that he has on an LGS 13 rate, is unduly hurt because it pays 18.47 cents per kWh and cannot pass on the charges to the customers beyond what they would pay on the residential rate (which Mr. Higgins calculates as 13.06 cents per kWh). Does the Company agree with this assessment?

A. The Company does not agree. The Company questions Mr. Higgins' choice of customer as well. His hypothetical customer is based on the average mobile home park customer size with an annual energy usage of 160,011 kWh. He estimates the annual billed demand to be about 625 kW, or about 52 kW a month. While this demand is reasonable for a mobile home park with usage of about 160,000 kWh, the LGS 13 rate has a minimum monthly billing demand of 200 kW. This means the customer is paying for 148 kW each month it does not use. That is, the customer is too small to benefit from the lower energy rates on the LGS rate. If this hypothetical mobile home park customer was truly concerned about the portion of its bill that it could not pass on to its residents, the customer would move to a more size appropriate rate schedule. If one were to look at current rates, the customer would pay about 13.92 cents per kWh on the SGS-10 tariff. This is significantly less than the 35.69 cents per kWh they pay on the LGS-13 tariff (corrected for the REST cap, the misapplication of DSM, and the missing application of the LGS-13 minimum billing demand requirement in Mr. Higgins' work papers). If we consider the proposed rates, the MGS tariff is a more appropriate tariff than on the LGS one. On the proposed MGS tariff the customer would pay 15.65 cents per kWh, which is reasonably close to the 14.16 cents per kWh the residential customers pay if the full rate

relief is granted and the proposed rates are approved without modification. As such, the rate design mismatch that seems to concern Mr. Higgins (page 49, lines 22-23) is not that much of a concern.

Q. What about master-metered mobile home parks that are large enough to be on the LGS-13 tariff?

A. The Company has identified 4 LGS-13 customers who are mobile home parks. These customers are not hurt as significantly as Mr. Higgins indicates. For the proposed rates, they pay an average of 13.97 cents per kWh, which is less than the proposed residential rate of 14.16 cents per kWh. Given that the mobile home park has costs associated with running the commercial operation, including the common areas, and other business administrative costs and operation costs over and above a residential home, this is reasonable.

Q. Mr. Higgins discussed master-metered mobile home parks in his testimony, but very little testimony has been presented elsewhere on this topic. Does the Company wish to discuss another issue relating to master-metered mobile home parks at this time?

A. Yes. As we reviewed the issue, another concern was raised internally. It has to do with the way certain tenants of master-metered mobile home parks are benefiting from a "Lifeline discount" when they are technically not a customer of TEP.

Q. Please describe the master-metered mobile home park ("MM") Lifeline Discount program.

A. Commission Decision No. 56819 (February 21, 1990) ordered TEP to extend its Lifeline program to residential tenants of master metered customers. TEP was ordered to file a quarterly report that was eventually changed to a monthly report which provided the number of tenants to whom discounts were offered by discount level; the number of kWh

consumed by discount level; the total dollar amount of discounts provided by discount level; the average discount per bill by discount level and a summary of total program expenses.

Q. Why is the MM Lifeline Discount Monthly Report no longer required to be filed with the Commission?

A. Commission ACC Decision No. 73912 (June 27, 2013) allowed TEP to modify the Lifeline discount tariff reporting requirements. In the TEP 2012 Rate Case, TEP proposed to consolidate all of the current Lifeline tariffs on Rate-01 and Rate-80; therefore, the reporting requirements would not be consistent with the tariffs. Therefore, we requested to modify our reporting requirements and we requested to file one annual report that no longer contained information relating to tenants of MMs. TEP no longer has to report anything relating to Lifeline Discounts for tenants of MMs to the Commission.

Q. Please describe the process to provide discounts to tenants of MMs?

A. MMs must assemble application forms from all their low-income customers who wish to participate in the Lifeline program and forward the forms to TEP. Qualifying tenants must reapply annually through the park or apartment operator. TEP will credit the discount for the tenants on TEP's bill for the MM. TEP has to prepare and post Master Meter Tenant Schedules on TEP's website. MMs must provide TEP with application forms and sign a contract with TEP indicating that the MMs will:

i. Read their customers' sub meters monthly and submit to TEP on TEP's Discount Claim Form the monthly usage and the dollar value of the discount which applies to each lifeline tenant;

ii. Deduct from the MM tenant's electric bill the amount of the lifeline discount; and

iii. Allow TEP, at TEP's discretion, to contact their tenants in order to verify the discounts.

Q. What would TEP like to do regarding the MM program?

A. Over the course of several rate cases, we have grandfathered tenants of MMs who had been receiving the frozen Senior Lifeline or frozen Medical Lifeline discount. The frozen Senior Lifeline and Medical Lifeline tariffs state the discount is available to tenants for MMs and apartments. However, as of the last TEP rate case, Rate R-01 makes no mention of the Lifeline discount with respect to master metered tenants. Currently, TEP holds contracts with 23 MMs by which we agree to offer Lifeline discounts to qualifying tenants. These contracts provide no end date and some of these contracts have been active for over 20 years. Tenants of MMs are not TEP customers at the cost of TEP's actual customers. TEP requests Commission approval to establish a uniform expiration date - one year after the rate effective date in this case - for all contracts, after which only customers of the utility (not customers of the MM facility) would receive the Lifeline discount.

Q. Mr. Higgins also had recommendations relating to the LFCR. Do you wish to address his recommendations?

A. Yes. I have addressed similar concerns in my response to Staff. Mr. Higgins has not offered any additional suggestions on how the Company may recover its lost fixed costs resulting from DG and EE and therefore has not offered any credible support for his recommendations. Additionally, on page 55, line 17, he seems to mischaracterize how lost fixed costs are shifted to the other customer classes if his recommendation to exclude LGS customers is approved. This class does benefit from DG and EE related programs and therefore generates lost revenues. Therefore if they are excluded from the LFCR, those lost revenues would most definitely be shifted to the other customer classes. His

statement is not correct. The Company recommends none of Mr. Higgins' recommendations relating to the LFCR be allowed.

Q. Mr. Higgins, on Page 3 of his Direct Testimony, also recommended that approximately $7,550,207 of any reduction allocated to the subsidy-paying classes be held back and used to fund the "Buy-Through" (Experimental Rider 14) rate. Does the Company's proposal allow for this recommendation?

A. No. As discussed in my Direct Testimony and later in this testimony, the Company does not support the approval of the "Buy-Through" Rider. Mr. Higgins' suggestion still results in costs to serve those participating customers to be shifted to remaining customers.

VII. RESPONSE TO ACAA.

Q. ACAA witness Ms. Cynthia Zwick discusses a few issues she has with the Company's proposals. The Company's witness Ms. Smith will address many of these issues, but please briefly discuss the Lifeline customers and the Company's proposals for them.

A. As discussed in my response to Staff and RUCO, the Company is proposing to reduce the number of Lifeline rates. In general, the Company is proposing to establish a flat credit to each eligible customer's monthly bill, and the bill would otherwise be calculated using the same rates as applicable for a non-participating residential customer on an equivalent rate. The credit will be the same for all open Lifeline rates, but will vary for the frozen Lifeline rates. For nearly all Lifeline customers the credits will be designed so that their bill impact is the same as or less than a non-participating Lifeline customer. There are approximately 11 of the 18 frozen Lifeline rates with less than 20 customers on them. A couple of these rates have a single customer on the rate. Since many of these 25 year old

rates produce bills that are nearly $500 per year or 46% less than a standard customer's bill for equivalent usage, there will be a handful of customers who may see a slightly larger increase, but they will still be receiving a $31-40 per month discount which is still nearly $500 per year for a few of these customers. The Company believes its proposal provides substantial discounts to eligible customers and by placing them on the standard rate for their base bill, they will be better prepared for moving to the standard rate when their economic circumstance improves and they move off of the Lifeline rate.

Q. Ms. Zwick has expressed concerns with how the Company is currently serving the Lifeline customers and the proposals the Company has made regarding discounts. Would you please respond to these concerns?

A. Yes. Ms. Zwick has discussed the hardships low income customers experience and the Company is sympathetic to these challenges. Under the Company's proposal, Lifeline customers will receive bill reductions of approximately $2.8 million annually, which significantly increases the existing discount level of $1.8 million. The actual dollar impact on the typical Lifeline customer is shown on my **Exhibit CAJ-R-2** to my Rebuttal Testimony and reflects a dollar change that averages between $3.77 and $4.41 per month for 98.5% of the Lifeline customers on the open rates, which reflects over $1 million additional discounts being offered to the Lifeline customers. With 18 frozen rates the impact varies substantially, but for over 98.5% of those on the frozen rates the increase is below $13.64 per month with many still saving nearly $500 per year when compared to the standard residential rate.

Ms. Zwick also suggested to increase the existing participation level of what she estimates to be 18% of the eligible customers (page 10, line 24) to a level of 50% of the eligible customers. The current number of Lifeline customers is approximately 15,000 and the discount funded by other customers is approximately $1.8 million per year with

the Company proposing to increase it to $2.8 million in this rate case. To nearly triple the participation level would also triple the necessary funding from other customers. As discussed in Dr. Overcast's testimony, many of the low income customers are not eligible customers due to a variety of reasons he describes. If the Commission approves Ms. Zwick's proposals, the Company would seek to recover those incremental bill discounts exceeding the $2.8 million already proposed to be recovered from other customers, through an adjustor mechanism. The Commission could also consider applying the Lifeline discount to the base cost of fuel and PPFAC. This would result in any incremental costs being shifted to non-Lifeline customers through the PPFAC adjustment.

The Company believes its proposal as supported in concept by Staff, is the best solution for providing discounts available to Lifeline customers.

Q. Do you believe Staff's proposal is fair to the Lifeline customers?

A. Yes. This method will let the Lifeline customers see the amount of their undiscounted bill. This provides customers with the appropriate pricing signals and will allow them to more easily adapt to standard rates when their economic situation improves. The Company believes it is a good solution and still provides a meaningful discount for the Lifeline customers. By basing a Lifeline customer's bill on the exact same rates as a standard residential customer, the Lifeline customers will be included with the rest of the residential class that pay the DSM surcharge as proposed by the Company in it direct case.

VIII. RESPONSE TO WAL-MART.

Q. Does the Company wish to address any portions of the testimony submitted by the two Wal-Mart witnesses?

A. Yes. First I would like to thank Mr. Tillman for his support of the Company's CCOSS, but there are a couple of areas I would like to briefly address in Mr. Tillman's testimony. I will not duplicate my testimony on revenue allocation here, but will simply refer to the proposals discussed in my rebuttal to Staff.

Q. On page 15, line 4 of his testimony, Mr. Tillman suggests the use of a rate support rider to address a portion of the inter-class subsidies reflected in the CCOSS. What are your thoughts on this suggestion?

A. On the surface the Company finds this to be an innovative suggestion. As proposed it would be revenue neutral to the Company, but would increase rates annually for the subsidized rate classes over the next few years. Comparable decreases would be realized by certain other rate classes. While in principle it sounds simple, the Company is concerned it might create additional, burdensome reporting requirements between rate cases.

The Company believes it would require further details to understand the process and to make sure it is documented in a way all parties understand what is to be expected. If Wal-Mart is serious about this proposal, it should submit a proposed Plan of Administration detailing how this proposal would work.

Q. Mr. Tillman has also requested some changes in the way revenues are recovered from the LGS rate class. Do you wish to address those issues here?

A. No. I believe his concerns are similar to an issue discussed by Kroger. I will recommend a change to the LGS rate in response to Kroger that I believe will address Mr. Tillman's concern.

Q. Wal-Mart witness Mr. Hendrix discussed the Buy Through rate and made recommendations relating to the program. Will you address that at this time?

A. No. Multiple parties submitted testimony on the Buy Through rate. I will address them all later in my testimony.

IX. RESPONSE TO SOLON, EFCA AND VOTE SOLAR.

Q. SOLON witness Mr. Seibel, EFCA witness Mr. Garrett and Vote Solar witness Ms. Kobor oppose many of the Company's proposals. Did you wish to discuss some of those issues?

A. Yes. I will address a few of their concerns. TEP witnesses Mr. Dukes, Mr. Tilghman, Mr. Bachmeier and Dr. Overcast have done a very good job of explaining the flaws in Mr. Seibel, Mr. Garrett and Ms. Kobor's misguided evaluation of how DG customers impact the Company's system and the "real" value they bring to the system as well as multiple unsupportable statements trying to justify why the Company should not change its rate design.

Q. Please summarize your reaction to the rate design testimonies of SOLON, EFCA and Vote Solar.

A. Like the UNS Electric case, the solar industry has not presented any meaningful rate design proposals other than to retain the status quo.

Q. Would you provide examples of why you believe the solar groups fail to lay out factual evidence and discuss reasonable alternatives to the existing net metering provisions?

A. Yes. Let me start with Mr. Seibel's misguided attempt to characterize anything the Company has proposed as being "retroactive". Obviously Mr. Seibel does not understand what "retroactive" means. If his interpretation were correct every rate case decided by this Commission would be "retroactive".

A rate case is noticed some period of time before it is filed. It indicates rates are going to be changed and that after Commission review and ultimate approval, those new rates would apply to the Company's customers on a prospective basis after the authorized rate effective date. That is exactly what the Company did with its notice to the net metering customers. They even received additional notice. Before June 1, 2015 the Company notified all pending net metering customers that the Company will be requesting a change to its rates (including the net metering rules) and that after Commission consideration and ultimate approval those new provisions would be applied on a prospective basis on and after the authorized rate effective date. There is nothing "retroactive" about this proposal. However, Mr. Seibel spends nearly 10 pages of his testimony trying to send up "smoke and mirrors" distractions to make parties believe his false accusations were somehow true.

Q. But didn't Mr. Seibel include an excerpt of an ACC open meeting where the issue of retroactive ratemaking was discussed?

A. Yes. The Commissioners are 100% accurate in their concern about approving any rate that would apply on a retroactive basis, but the Company has not proposed to apply anything retroactively. They have proposed to apply the change prospectively after the

rate effective date. That, by definition, is not "retroactive" it is prospective application of a change.

Q. Mr. Seibel states (at 12-23) that without net metering, their clients do not believe solar projects would be financially viable. Is the Company eliminating net metering?

A. Not at all. The Company is still proposing that DG customers benefit from full retail net metering for the customer's production that occurs in the same hour as their consumption. The Company's proposal still allows them a credit for any excess production that goes back to the utility's system but is also proposing changes to the rates applicable to partial requirement customers that will allow for more of the costs associated with providing service to that customer to be recovered.

Q Are there other areas of Mr. Seibel's testimony you wish to address?

A. Yes. I will point out a few more mischaracterizations he has generated to promote the "smoke and mirrors" he is attempting to create. On page 26, line 21 he mentions that TOU plans are easy to understand and can help people reduce their peak kW load when it coincides with the Company's overall peak demand. What he fails to acknowledge is that TOU rates can actually contribute to the utility system's overall peak demand. The TOU rate is not a substitute for a demand charge when it is being used to reduce peak demand.

Q. Why is that?

A. Currently, TEP's summer peak period is 2:00 pm to 8:00 pm. The price is higher during the peak period and does discourage usage during that time, but could actually result in an increased peak during that period whereas a demand charge provides an economic incentive to change how energy is used in a way to help reduce the system's peak. A simple example would be under the TOU rate it wouldn't matter to the customer whether 1 kWh were used each hour of the peak period or if 6 kWh were used in one hour of the

peak period. Either way the customer pays the peak volumetric rate for 6 kWh. However, the customer who uses 1 kWh each hour for all six hours only contributes 1 kW of peak load on the system. The other customer contributes 6 kW of peak load on the system - which is six times the capacity burden of the first customer. The customer doesn't care because TOU rates provide no price signal to change how the energy is used during that peak period.

Q. Do you have any comments on EFCA's witness, Mr. Garrett's testimony?

A. Yes. Mr. Garrett also makes some statements that I would like to address. His testimony seems to convey a theme of keeping the status quo and even taking a step backwards from the current rates in effect for certain large customers. He goes so far as to recommend (7-18) removing ratcheted demand on existing rates (LGS) that have had this form of demand billing in place for years. This shows his lack of concern as it relates to the appropriate cost being recovered from the cost causer. To remove or reduce the ratchet results in additional costs being shifted to the highest load factor customers. This proposal flies in the face of sound rate making principles.

Q. On page 10, line 11, Mr. Garrett seems to indicate that subsidies and costs shifts are an important part of rate design and should be retained, not changed. Do you agree with this statement?

A. Not at all. These types of comments intrigue me. They would only make sense coming from an entity that is not paying its fair share of the costs and wants to continue this inequity to protect a business model that has been created to capitalize on this design. I believe most of the major parties in this case, except the solar representatives, would disagree with this statement. The Company, Staff, RUCO, AECC, Wal-Mart, Kroger, APS, and the DOD all agree subsidies should be reduced or where possible, eliminated. The hard part is agreeing on how fast. To say it "should be retained, not changed"

completely disregards rate design theory. If that were true, there would be no need for CCOSSs, which are an important part of any rate case. I believe Wal-Mart witness Mr. Tillman (7-3) said it best, "The cost of service study is foundational in establishing distribution of the utility's authorized revenue requirement amongst the various customer classes." Intra-class and inter-class subsidies resulting from antiquated rate design is a flaw in the system, not an attribute.

Q. Mr. Garrett also states that periodic rate cases and the LFCR will address under-recovery of fixed costs. Do you agree that delaying the recovery of fixed costs is more appropriate than correcting rate design to affect a more timely and accurate recovery of those costs?

A. No. Mr. Garrett seems to not only ignore the theory of fair rates and the recovery of costs from the cost causer, he also fails to recognize that rate cases take nearly two years to prepare and prosecute, which means under recovered costs are rarely recovered from the cost causer. He also fails to recognize that the LFCR recovers less than 41% of the lost revenues created by EE and DG and ultimately redistributes those costs to all participating classes.

Q. Mr. Garrett seems to believe TEP is using its current loss of load as the primary justification for changing its net metering rates. Do you agree with his characterization?

A. No. Attempting to modify its rate design to create more appropriate and fair rates is the Company's primary reason along with creating rates that allows the Company to recover its costs and authorized return. The loss of load is simply a component in the equation used to arrive at final rates.

Q. Does the Company believe that demand charges <u>require investments</u> in advanced technology that are not feasible for typical residential customers?

A. No, not at all. The customer would easily be able to adjust habits in very minor ways to start seeing a savings on their bill. Timing is the key and all it takes is a small effort to pay attention to when they start a particular appliance. Rates are already based on normal usage so a change from normal will likely produce a savings. No expensive technology is needed at all.

Q. On page 20, line 5, Mr. Garrett indicates he believes DG facilities are somehow similar to other forms of energy efficiency. Do you agree?

A. Not at all. In fact, a customer might very easily do just the opposite. They could keep their thermostat set 5 to 10 degrees cooler than someone trying to be energy efficient because they have been misinformed that all of their energy is free. The facts are just the opposite if this occurs as the sun is going down. Because of the increased energy needs to maintain the cooler temperatures in their home, the customer ultimately puts additional burden on the system and that burden will likely be greater than a similarly situated customer who is trying to conserve energy with a thermostat set at a higher level.

This example also provides insight into just how different a DG customer is from another customer practicing energy efficiency. As a customer becomes more efficient, their load requirements and, hopefully, their peak requirements will reduce. Solar customers could do just the opposite. Since solar production is not coincident with the system peak, the customer could develop bad habits that actually contribute to a higher peak.

Additionally, Mr. Garrett's attempt to compare DG customers to a vacant home are not accurate either. A vacant home with zero consumption will not put a kW load on the system. A DG customer can have zero billed kWh (over 40,000 bills did in the test year),

but they will still place a kW load on the system and it is likely to be higher than the customers' load demand.

Q. Do you have any final comments relating to Mr. Garrett's testimony?

A. Yes. Another mischaracterization of the facts can be found on page 54, line 5. Mr. Garrett states that; "...changes in a customer's consumption behavior have little to no impact on their bill once a ratchet is established." In my opinion, with the fuel and purchased power costs being nearly 26% of a typical customer's bill, there is enough cost remaining to be considered an impact on the customer's bill.

Q. Do you have any comments on the testimony submitted by Vote Solar witness, Ms. Kobor?

A. Yes. Many of the comments made by Ms. Kobor are being addressed by other Company witnesses, Mr. Dukes, Mr. Tilghman, Mr. Bachmeier and Dr. Overcast but there are a few statements and suppositions that she has made that I would like to address.

One of the comments she made on page 5, line 24 is that the LFCR is "...designed to address <u>ANY</u> issues related to fixed cost recovery from DG and energy efficiency ("EE")." (Emphasis added.) This is a statement similar to the other solar witnesses in that it overstates the facts and is just untrue. My testimony in response to Staff relating to changes to the LFCR mechanism discusses at great length, just how much the current LFCR design under-recovers costs. Staff even agrees that costs are left unrecovered, but they are not willing to make changes because they believe other actions could make up for the losses. Therefore, to say <u>any</u> issues relating to fixed cost recovery from DG and EE is completely wrong. Only a portion of those lost fixed costs are recovered through the LFCR and those are recovered from the non-participating customers with very little contribution being made by net metering customers to the losses they generate.

Q. What is the Company's opinion as it relates to Ms. Kobor's accusations on pages 10 through 14 of her testimony that the Company is proposing its rate design changes to address issues created by a small portion of their customer base?

A. The Company disagrees with Ms. Kobor. Fair cost recovery is the target of our rate design changes. The redesign of rates in a manner to more appropriately recover costs is right for all customers. It just happens to reduce (not take away) certain partial requirement customers' opportunity to enjoy underpaying for the services they receive. Another much higher priority for the redesign of rates is to promote newer technology in a cost effective manner which will provide benefits to the entire system and ultimately all customers.

On page 13, line 20, Ms. Kobor states that 98% of the residential customers TEP alleges are causing a cost shift are not net metering customers. The Company's test year billing frequency study indicates that R-01 net metering customers alone generated over 40,000 monthly bills for zero kWh (out of 74,000 total annual bills). This compares to 37,700 bills for full requirements customers that were for zero consumption (out of 4.1 million bills). Over 50% of the zero bills on the system are generated by DG customers and this number is growing fast based on monthly additions of DG systems[6]. The other types of low-use customers are steady and are not changing substantially from year to year and certainly not at the pace of added DG customers. Based on recent census data,[7] the percent of vacant homes has decreased by 0.4% when comparing the 10-year average to the average over the last 4 years. This compares to the nearly 300% increase in DG systems since the last test year. Plus, the grandfathered DG customers will also be in base rates at the conclusion of this case so the Company will be treating grandfathered DG

[6] In reality the number of DG systems installed since the end of the test year in the Company's last rate case has grown from approximately 3,000 to approximately 12,000 as of the writing of this testimony. That is an approximate 300% increase in DG systems since the end of the last test year. That is not "minimal" as Ms. Kobor wants us to believe.

[7] http://www.census.gov/housing/hvs/files/currenthvspress.pdf

customers just like all of the other low use customers. It is only the new DG customers that will be subject to the more cost based rate design being proposed herein.

Q. On page 23, line 8 Ms. Kobor makes an implication that the cost shift attributable to partial requirement solar customers is less than $1.5 million. Do you agree with this estimate?

A. No. As stated by the Company's witness Mr. Dukes at 21-26 of his Direct Testimony, the fixed cost recovery shortfall of a DG customer sized to meet 100% of their annual load is approximately $61 per month on average. With nearly 12,000 current residential net metering customers the estimated loss in fixed cost recovery would be an estimated (12,000 customers x $61/month x 12 months) $8.78 million per year for just the DG customers. With a three year rate case cycle that would be a minimum of $26 million lost with no DG growth (assuming the loss wasn't rolled into rates and charged to the other customers). This amount is not "minimal" as Ms. Kobor states at 11-15.

Q. Ms. Kobor indicates that cost shifting within the rate classes is an inherent part of rate design on page 24, line 7. If that is the case, is it appropriate for a utility to never try to reduce this cost shift?

A. No. The Company is responsible for creating a rate design that is fair and equitable for all of our customers. Since meter technology has advanced, now is the time to move that direction. It is time to start addressing the intra-class subsidies created by antiquated rate design.

Q. Would you like to comment on Ms. Kobor's reference to "costs avoided" on page 28, line 29 of her testimony?

A. Yes. Ms. Kobor makes the following statement in support for why crediting DG at the utility-scale PPA price is not appropriate; "From a non-participating ratepayer

perspective, the right question to ask is; what is the level of costs avoided by the non-participating customers as a result of the exported DG?" (Emphasis added)

First the question references the "costs avoided". The "costs avoided" are actually the weighted average cost of purchased power that the customer would actually use absent the excess solar generation. That amount is closer to $0.04 per kWh. Even though the value of the excess generation is probably less than the weighted average cost of purchased power, the Company is willing to use the utility-scale solar PPA as a proxy. Her question actually supports the use of utility-scale solar PPAs as a proxy for the value of excess solar generation as a benefit to the solar DG customer. The "cost avoided" by the non-participating customer is less than the proposed RCR rate, not more.

Q. Starting at page 52, Ms. Kobor tries to explain why TOU rates are good and should be considered over demand rates. Does the Company believe TOU are a preferred alternative to demand charges?

A. It depends on your goal. The Company is not opposed to TOU rates for the energy component of a three-part rate, but believes they should be offered in conjunction with a form of recovery based on the level of demand placed on the system, especially for the unique usage patterns of a partial requirements DG customer. While TOU rates do help to encourage the movement of consumption to off-peak periods, by themselves they do not necessarily reduce the customer's contribution to the system peak. While reducing a customer's peak is not the Company's only goal when proposing a demand rate, it is a beneficial side effect of offering a more appropriate rate design.

Q. Ms. Kobor (at 58-1) seems to think the LFCR is specifically designed to address under-recovery of fixed costs due to DG and EE. Do you have any concerns with that statement?

A. Yes. As I've stated previously in my testimony, the LFCR does recover a portion of the lost fixed costs realized by Commission mandated EE and DG programs, however, it falls substantially short of recovering all of the lost fixed costs. Ms. Kobor fails to mention the continuing theme of shifting the losses associated with DG (and EE) programs to the other customers. The Company prefers to mitigate some of this cost shift through more cost based rate design. Because of the current LFCR restrictions on the amount of lost fixed costs the Company is allowed to recover approximately $13 million went unrecovered in 2014 and approximately $19.6 million went unrecovered in 2015. This is a two year total of $32.6 million. Corrected rate design would be a much better option since it will keep part of the costs with the cost causers.

X. RESPONSE TO KROGER.

Q. Do you have any rebuttal for Kroger's witness, Mr. Baron?

A. I have already addressed the revenue allocation earlier in my testimony. I will discuss the Buy-Through rate later in my testimony.

The first issue I will address is Mr. Baron's suggestion that a portion of the cost recovery originally proposed to be included in the volumetric charges for the LGS-TOU be moved to the demand charge. The Company is agreeable to addressing this issue. The rates included in my attached **Exhibit CAJ-R-3** reflect a modification to the LGS-TOU rates that moves a portion of the revenue recovery from the volumetric rate components to the demand charge.

The other issue I would like to address at this time is his proposal to create a Multi-Site Commercial rate design. This is not something the Company is interested in pursuing. The Company has been moving to rates created based on individual service points and while there are a few grandfathered large accounts with some grouping of a customer's service points, it is not something that the Company believes is in the best interest of its entire customer base. Rates are designed to recover costs allocated based on service points. Billing determinants are based on individual service points. Costs are tracked by individual service points. Delivery costs are based on local facilities and those cannot be averaged over customers who use substantially different delivery service facilities. To start grouping customers would require the creation of a separate rate class and thus additional tracking and combining of costs. Not knowing which customers are eligible to combine and what that combined load actually would be also adds to the uncertainty. Assuming it would reduce some customer's billing determinants, the rates would need to be increased proportionally. The total cost to serve them would be the same and if the rates are designed correctly, the end result is a lot of additional work with no definable savings for the customer or the company. The Company is moving toward more homogenous groupings of our customers. But to create another special study and pass the cost on to the remaining customers is not what the Company is interested in doing at this time.

XI. RESPONSE TO SWEEP/WRA.

Q. SWEEP witness Mr. Schlegel has filed revenue requirement testimony discussing a couple of suggested changes to the Company's proposals. Would you like to mention his suggestions?

A. Yes. There were two suggestion made by Mr. Schlegel that I have either already discussed in my Rebuttal Testimony or will be addressed by another Company witness,

Ms. Smith. Ms. Smith discusses why the DSM related costs should not be included in base rates and I have, in response to Staff, discussed what changes the Company has proposed for the LFCR. While the Company appreciates Mr. Schlegel's suggestion of offering a full decoupler, the Company believes the LFCR will sufficiently address its concerns if modified in accordance with our proposal.

Q. SWEEP/WRA witness Mr. Baatz has filed testimony in opposition to a number of the Company's proposals. Would you like to address his objections?

A. Yes.

Q. What issues presented by Mr. Baatz do you wish to address?

A. I have discussed this earlier in my rebuttal to RUCO witness, Mr. Huber, but on page 13, line 17, Mr. Baatz tries to compare a regulated utility's rates to gasoline at a fueling station or food at a grocery store, but what he fails to acknowledge is that his examples are in a competitive market and are in no way similar to a regulated utility. In fact, I was surprised he chose hotels as one of his examples. Most people do not rent hotel rooms "volumetrically" or should we say, by the hour. His analogy is simply wrong.

Q. Mr. Baatz is also opposed to increasing the basic customer charge. Has he provided any additional information that you have not addressed in your Rebuttal Testimony of Mr. Huber of RUCO on the same topic?

A. No. The Company's witness Dr. Overcast has done an excellent job of explaining why the higher basic service charge is appropriate and why using the minimum system approach is appropriate to design a cost based fixed charge applicable to the customer. Also, based on the Company's research, recent Commission actions or in the case of electric cooperatives, their boards of directors have approved a number of basic service

charges at least as high as the one the Company is requesting. Please refer to the table provided earlier in my testimony in response to RUCO's witness, Mr. Huber.

Q. Mr. Baatz spends some time on page 21 of his direct testimony stating that he believes that eliminating the last two inverted block rates will somehow discourage the customer from conserving energy. Do you agree with this assumption on his part?

A. No. Mr. Baatz, in the same manner as I discussed in my rebuttal of RUCO's witness Mr. Huber, has not provided any support or a study that might indicate a customer has any knowledge as to when they might move from tier 1 to tier 2 to tier 3 to tier 4. Please refer to my rebuttal of Mr. Huber for further support for why Mr. Baatz is wrong.

Q. Would you like to respond to Mr. Baatz's suggested denial of the Prepay rates?

A. Yes. On page 30, he starts discussing the Prepay rate. He indicates SWEEP had several concerns about the Prepay rate. The Company has already discussed why it believes the Prepay rate should be approved. Staff has added a couple of conditions to its approval and the Company's witness Ms. Smith has addressed these issues. I have mentioned earlier in this testimony that the Company would be willing to expand the Prepay rate to Lifeline customers by adjusting the daily service charge by a daily equivalent of the final open Lifeline discount approved in this proceeding.

XII. AGS EXPERIMENTAL RIDER 14 ("BUY-THROUGH").

Q. Which Commission Staff and/or Intervenor parties addressed the Company's proposed Experimental Rider 14 in their Rate Design testimony?

A. Commission Staff, AECC, Wal-Mart, Noble, Kroger and AIC addressed the issue.

Q. Please summarize the Intervenor Parties' positions regarding the Company's proposed Experimental Rider 14.

A. Staff is neutral on adoption of Experimental Rider 14 and does not object to its adoption if there are no adverse impacts on non-participating customers. AECC, Noble, Kroger and Wal-Mart support adoption of Experimental Rider 14 with recommended revisions that I will discuss in more detail. My rebuttal of AECC and Wal-Mart will be true for Noble and Kroger even though I do not address them individually. The issues are the same and my rebuttal would be the same.

AIC opposes adoption of the Rider because it benefits only the customers fortunate enough to be chosen to participate and shifts costs to non-participating customers. Also, AIC notes that a similar program (AG-1) was implemented by APS in 2012 and the potential effects of that program on the company and its customers are uncertain. AIC recommends that the Commission should wait until it is able to analyze the performance of the APS AG-1 rate program before requiring the implementation of a similar program by TEP.

A. <u>Commission Staff.</u>

Q. Please summarize ACC Staff comments on the Company's proposed Experimental Rider 14.

A. Mr. Solganick stated that Staff looks forward to the input of other parties and does not object to the implementation of Experimental Rider 14 if there are no adverse impacts or costs to other customers. In particular, Staff opposes recouping any lost revenue in the LFCR and opposes any deferral of lost revenue.

Q. Do you agree with Staff's position that no lost revenue resulting from the implementation of Experimental Rider 14 should be recovered in the LFCR or deferred for recovery at a later date?

A. As clearly stated in my Direct Testimony, the Company is not supportive of the "Buy-Through" rate in part because it will likely result in lost fixed cost, which the Company believes should be recovered fully in the LFCR once quantified. I will discuss the Company's concerns and objections to this rate later in my Rebuttal Testimony. Staff indicated they do not object to a "Buy-Through" mechanism if there are no adverse impacts and no costs to the other customers. This includes not allowing any identified costs to be recovered through the Company proposed method of including it in the LFCR mechanism.

As stated in my Direct Testimony, with regards to the "Buy-Through" rate since TEP does not have staff available to monitor and offer this type of service, providing it will require additional personnel, additional processes to track and verify the flow of energy, incremental Transmission balancing services, additional billing equipment and billing processes, among other things. This will all be required to offer a special deal to a few large customers to gain the opportunity to save on energy while the market is down, only to come back for full retail service when the market returns. Since the fixed cost of the Company's generation facilities are included in base rates and recovered on a test year assumed level of sales, any lost sales due to this program will produce lost fixed cost recovery unless the customers pay the full non-fuel rate. We would prefer not creating a potentially subsidized rate for a few select large customers just to create more lost revenues to be recovered from all other customers.

B. AECC

Q. Please summarize AECC's recommendations for proposed Experimental Rider14.

A. AECC witness Mr. Higgins recommends adoption of a buy-through program "that is as similar as reasonably possible to the AG-1 program currently in effect in the APS service territory."[8] Mr. Higgins favors adopting some of the features of the buy-through program presented by the Company, but recommends changes to program eligibility, the proposed monthly management fee, the mechanics of fixed generation cost recovery, and the terms of return to standard generation service. He also recommends clarification of the program term.

Q. Do you agree with AECC's recommendations for Experimental Rider 14?

A. No. I will address each of AECC's recommendations individually.

Q. Please summarize AECC's recommendations related to Rider 14 program eligibility.

A. AECC argues that the Company's proposed program cap of 30 MW is too low and that it should be increased to 60 MW. AECC also recommends maintaining the overall minimum load requirement of 3 MW but broadening the range of customers eligible to participate by allowing aggregation of smaller loads in the LGS class owned by the same corporate entity to achieve the 3 MW threshold. Each single entity aggregated to reach the 3 MW threshold should have experienced a billing demand of at least 200 kW in the previous year to be eligible.

[8] Direct Rate Design Testimony of Kevin Higgins, page 3:22-23.

Q. Do you agree with the AECC recommendation to reduce the minimum load size for participation and allow aggregation of corporate loads?

A. No. While the APS AG-1 program can serve as a model for certain elements of a similar program for the Company, the proposal should not be identical to the APS AG-1 program. The Company and APS are utilities of much different size, generating capacity and customer characteristics. In 2014, the APS system had a peak demand approximately 3 times larger than that of the Company. As a result, APS is most likely able to take advantage of economies of scale that are not available to a company the size of TEP. The Company does not currently have personnel on staff to manage a program like that proposed in Experimental Rider 14, much less to manage aggregation of corporate loads for such a program as Mr. Higgins is proposing.

Finally, the order in the Fortis acquisition of UNS Energy, parent of TEP and UNS Electric, specifies that in their next rate cases "TEP and UNS Electric will propose a pilot program for a "buy through" tariff available to Large Light and Power Service and Large Power Service customers, respectively."[9] As mentioned earlier, the Company is proposing Experimental Rider 14 as a condition of the Fortis merger settlement agreement, but is not supporting its adoption. Therefore, the Company sees no reason to expand the availability of Experimental Rider 14 beyond the customer classes specified in the Fortis merger settlement agreement.

Q. Do you agree with AECC that the Company's proposed monthly management fee should be reduced from the $0.004/kWh to $0.002/kWh?

A. No. The only reason Mr. Higgins gives for the Company's proposed management fee being "excessive" is that it is "six times greater" than the APS management fee. APS likely

[9] ACC Decision No. 74689 (August 12, 2014), Attachment A, p. 5.

has scale economies that do not exist for the Company. Therefore, a higher charge for the service is reasonable.

Furthermore, APS has indicated that the net impact of the AG-1 program has been losses in the range of $24.4 million.[10] Rather than the proposed management fee being "excessive" it is highly likely that the APS AG-1 management fee is inadequate and partly responsible for the AG-1 program losses even if tripled as suggested by Mr. Higgins.

Q. Please summarize Mr. Higgins recommendations regarding the Company's fixed generation cost recovery.

A. The Company proposed that participating customers pay 100% of the customer's generation-related demand component for all billing demand. Mr. Higgins recommends that charges for generation-related services should be limited to a charge for reserve capacity applied to 15% of the customer's billed demand priced at the unbundled generation demand charge. Essentially, Mr. Higgins is recommending that the recovery of generation-related fixed costs from participating customers be reduced from the Company's proposal of 100% to 15% for the entire term of service under the Rider.

Q. What are AECC's objections to the Company's proposed recovery of fixed generation costs from participating customers?

A. Mr. Higgins argues that while some assignment of cost for generation reserves may be appropriate, the Company's proposal is excessive and is more comparable to a stranded cost charge. He argues that the stranded cost approach should be rejected unless the customers are being provided with an opportunity to transition permanently to market pricing. Mr. Higgins bases his recommendation of 15% on the Company's planning reserve margin.

[10] Direct Rate Design Testimony of Gary Yaquinto, page 13:13.

Q. Do you agree that the Company's proposal is comparable to a stranded cost charge?

A. No. Stranded cost is defined as the net present value difference between the market value of an asset and the book value. If the market value is less than book, stranded costs result. In other words, a stranded cost calculation would look at the entire value of the asset up to the time the asset is retired. The Company has invested in generation assets to serve all customers on the system including those who might participate in the Rider 14 program. The capital costs related to these generation assets are collected from the customers served by them over the useful life of the assets. A recovery of 100% of fixed generation costs over the 4-year term of the pilot is not equivalent to a stranded cost charge, which would be calculated over the entire remaining life of the asset. In fact, the fixed generation costs reflected in rates are set to recover that assets depreciation expense and return for the life of generation assets on a monthly basis over the life of those assets. Recovering 100% of those costs over a 12-month period would be much less than a system exit fee based on stranded costs.

Q. Do you agree with Mr. Higgins' suggestion that the first $7.5 million of any revenue requirement reduction should be apportioned to "subsidy-paying" classes to help absorb any TEP revenue deficiency ascribed to lost generation revenues?

A. No. As discussed in my Direct Testimony and in this Rebuttal Testimony, the Company does not support the approval of the "Buy-Through" Rider 14. Mr. Higgins' suggestion is innovative on the surface, but still results in the costs associated with providing the "Buy Through" option to a select few customers coming out of the Company's total revenue requirement and thereby being paid for by the remaining customers.

Q. Do you agree with Mr. Higgins that the price for returning to full utility service before the expiration of the program should be lowered from the Company's proposed Dow Jones Palo Verde Index plus $20/MWh to the Index plus a maximum of $4/MWh?

A. No. This charge is being proposed to discourage a customer from returning before expiration of the program. Therefore the penalty charge needs to be large so that the customer has a price signal to not just jump back on regulated service the moment the market turns. The APS AG-1 program specifies the Dow Jones Palo Verde Index plus $10/MWh. Reducing the adder to $4/MWh has no justification. Again, TEP wants to protect itself and its customers from the types of losses that APS has experienced as a result of its AG-1 program.

Q. What are AECC's recommendations with respect to clarification of the Experimental Rider 14 program term?

A. AECC recommends that the program term should be restated to indicate that Rider 14 will continue to be available at least until the start of the first rate-effective period following a general rate case occurring no less than four years from the program start date.

Q. What is AECC's justification for this recommendation?

A. While Mr. Higgins states that he does not disagree with the Company's proposal to target a four-year period for the program term, he believes it is important that any program extension or modification be considered in the context of a future general rate case prior to termination of the program.

Q. Do you agree with the AECC recommendation to extend the program term at least until the start of the first rate-effective period following a general rate case occurring no less than four years from the program start date?

A. No. If the Company is ordered to implement Rider 14 it should be for a maximum of the four years specified in the tariff. AECC seems to want the best of both worlds with this recommendation.

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

Q. Please summarize Wal-Mart's recommendations for proposed Experimental Rider 14.

A. Wal-Mart witness Chris Hendrix recommends approval of Experimental Rider 14 with the following changes:

- TEP's proposed management fee of $0.004/kWh should be rejected and the Company should be required to file a cost-justified management fee proposal.
- The minimum participation level should be reduced to 1,000 kW and corporate aggregation should be allowed to meet the limit.
- All rate classes should be allowed to participate in the program.
- The total participation limit should be raised to 250 MW, based on the amount of wholesale electricity purchases currently undertaken by TEP.
- Experimental Rider 14 customers should not be responsible for any of the Company's generation related charges because the program is simply replacing market purchases.
- There should be no limit on the term of the program.

Q. Do you agree with Wal-Mart's recommendations for Experimental Rider 14?

A. No. I will address Wal-Mart's recommendations individually.

Q. Do you agree with the Wal-Mart's recommendation to reject the Company's proposed management fee and require TEP to file a cost-justified management fee proposal?

A. No. Proposed Experimental Rider 14 is an optional program. If any potential participants believe the management fee is too high, they can elect not to participate. Because the level of participation is unknown, the level of personnel necessary to monitor the program, the equipment and software needs are also unknown at this time. Thus, the initial charge should be large enough to capture any and all likely costs. The Company believes the proposed $0.004 per kWh meets those needs.

Q. Do you agree that the minimum participation level should be reduced to 1,000 kW and corporate aggregation should be allowed to meet the limit?

A. No. As I addressed in the rebuttal to AECC concerning this issue, TEP does not have the resources to deal with smaller customer sizes than specified in the proposed Rider 14 or aggregation of loads. And if this were approved the administration charge would need to be increased substantially.

Q. Do you agree with Wal-Mart's recommendation that all rate classes be allowed to participate?

A. No. As mentioned earlier, the Fortis acquisition settlement agreement specified only that TEP make a program like that proposed in Rider 14 available to customers in the Large Power Service rate class.

Q. What is Wal-Mart's basis for recommending that the total participation cap be raised to 250 MW?

A. Mr. Hendrix notes that according to the Direct Testimony of TEP witness Michael E. Sheehan, the Company will be purchasing between 250 and 350 MW of capacity from the

wholesale market. Mr. Hendrix bases the 250 MW cap recommendation on that number and argues that removing that 250 MW from the Company's market purchases would "significantly reduce the Company's reliance on the wholesale market and transfer the market risk to customers who are willingly participating in the AGS program."[11]

Q. Do you agree with Mr. Hendrix that the total participation cap should be raised to 250 MW?

A. No. Mr. Hendrix's recommendation ignores the entire process of Integrated Resource Planning. An Integrated Resource Plan ("IRP") is a utility plan for meeting forecasted annual peak and energy demand, plus an established reserve margin, through a combination of supply-side and demand-side resources over a specified future period. It is a dynamic process and a utility's IRP will typically be examined, modified, and acknowledged in a proceeding before a regulatory commission.

The Company's IRP was developed via extensive modeling and dynamic optimization to select the best combination of supply and demand-side resources to serve projected Company loads plus a reserve margin. Also, the Company's IRP has been reviewed and acknowledged in a separate IRP proceeding by the Commission. Mr. Hendrix proposes to throw out that entire process and make ad hoc adjustments to the Company's IRP in a rate case, not in a proceeding where these planning issues are more closely examined.

Finally, the 250-350 MW of market power purchases cited earlier in the Company's IRP has not been planned for the Rider 14 customers. Prospective Rider 14 customers should not be allowed to evade their responsibility for cost recovery of the utility's fixed generation assets that were procured to their benefit under an obligation to serve.

[11] Direct Rate Design Testimony of Wal-Mart Witness hendrix, pages 7, 11.

Q. Do you agree with Wal-Mart's statement that Experimental Rider 14 customers should not be responsible for any of Company's generation related charges because the program is simply replacing wholesale market purchases?

A. No. The generation related charges included in rates are not avoidable. For the same reasons that I believe the generation costs should be included in the LFCR rates, I believe these customers should be required to pay the level of generation costs they were allocated in the most recent rate case. All resources that the Company relies on to serve loads on the system are procured for the benefit of all customers. All customers should therefore be responsible for their share of allocated costs.

Q. Do you agree that the program term should be unlimited?

A. No. "Experimental" means a program that has to be tested and evaluated to determine whether it merits becoming a permanent rate structure. As mentioned earlier, the Fortis Acquisition Settlement specified that TEP propose a pilot program for a buy-through tariff. Pilot programs by definition are of limited duration.

Q. Mr. Hendrix has also requested that a Renewable Buy-Through Generation Service be established. Is this something the Company would support?

A. No, for the same reasons I have described in response to the request to establish the Rider 14 Buy-Through rate.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

Exhibit CAJ – R – 1

Tucson Electric Power Company
Summary of Changes: Direct to Rebuttal
Test Period Ending June 30, 2015

	Direct	Rebuttal
CCOSS		Slight modifications (A&G allocations and meter cost)
Revenue Allocation	Weighted to allocate more of increase to subsidy-receiving classes	Revenue allocation more reflective of Staff's proposed allocation
Residential Service	Basic Service Charge- $20 Mandatory 3-part for DG customers	Basic Service Charge- $17 Would consider adding a 3-part rate w/on-peak hours if requested
Lifeline	$1.8 million in test-year discounts Reduced from 27 rate structures to 5 open lifeline rates	$2.8 million in discounts Place all Lifeline customers on standard rate design with flat discounts applied to 5 open rates & 3 frozen rates
Small General Service	Basic Service Charge- $30 Mandatory 3-part for DG customers	Basic Service Charge- $27 Would consider adding a 3-part rate w/on-peak hours if requested
Medium General Service	250 kW cap Move to the LGS rate after hitting the 250 KW cap one time	Transition plan details Rate design open 18 months Seasonality Clause 300kW cap, move MGS to LGS after hitting cap two times in 12 months
Large General Service	Basic Service Charge - $1,000 Reach cap once before moving to LPS	Basic Service Charge - $950 for Standard and TOU rates LPS-Hit 5,000 KW cap twice LGS TOU- moved a portion of cost recovery from energy back into Demand
Large Power Service	Basic Service Charge - $2,000	Basic Service Charge - $10,000
138kV rate	Basic Service Charge - $3,000	Basic Service Charge - $15,000 Grandfathering provision for presently grandfathered customers
Prepay	Unavailable to Lifeline	Provision added for Lifeline Offer as a pilot program
PPFAC	Changed to a 12 month rolling % adjustor	12 month rolling per-kWh adjustor
Interval Data Request and AMR Opt-Out Charges	Introduction of different service fees	Accepts Staff's recommendations
Residential Community Solar Program		RCS program rates match standard rates. $1/KW adder
Master Metered Program		Requesting ACC approval for Master-Metered Lifeline expiration date

Exhibit CAJ – R – 2

Tucson Electric Power
Bill Impacts
Test Year Ending June 30, 2015

Class Description	Customer Counts 6/1/16	New Annual Bill	Annual Bill Change	$ Change from Standard Tariff	Revised Percent Change to Total Bill	Monthly $ Change in Bill
Residential Service	344,070	$1,392	$125		9.9%	$10.41
Residential Lifeline R-01LL	7,673	$1,212	$53	($180)	4.6%	$4.41
Residential Lifeline R-04-01F	364	$1,020	$91	($372)	9.8%	$7.60
Residential Lifeline R-05-01F	880	$1,212	$137	($180)	12.7%	$11.40
Residential Lifeline R-06-01F	4,652	$1,212	$164	($180)	15.6%	$13.64
Residential Lifeline R-08-01F	523	$912	$130	($480)	16.6%	$10.80
Residential R-201A	11,441	$1,315	$117	($77)	9.8%	$9.77
Residential Lifeline R-201AL	230	$1,135	$45	($257)	4.2%	$3.77
Residential Lifeline 06-201AF	241	$1,135	$165	($257)	17.0%	$13.73
Residential Lifeline 08-201AF	9	$943	$211	($449)	28.9%	$17.61
Residential TOU R-80	7,867	$1,356	$232	($36)	20.6%	$19.31
Residential Lifeline TOU R-80LL	106	$1,176	$160	($216)	15.7%	$13.31
Residential Lifeline R-04-21F	2	$1,014	$192	($378)	23.4%	$16.03
Residential Lifeline R-05-21F	1	$1,206	$249	($186)	26.0%	$20.74
Residential Lifeline R-06-21F	15	$1,014	$113	($378)	12.5%	$9.38
Residential Lifeline R-08-21F	6	$906	$216	($486)	31.3%	$18.01
Residential Lifeline R-04-70F	4	$1,014	$135	($378)	15.3%	$11.24
Residential Lifeline R-05-70F	7	$1,206	$208	($186)	20.8%	$17.32
Residential Lifeline R-06-70F	50	$1,206	$232	($186)	23.8%	$19.29
Residential Lifeline R-08-70F	15	$906	$180	($486)	24.9%	$15.03
Residential TOU Super Peak	214	$1,311	$227	($81)	20.9%	$18.88
Residential Lifeline TOU Super Peak	7	$1,131	$155	($261)	15.8%	$12.88
Residential R-201B	615	$1,286	$246	($106)	23.6%	$20.48
Residential Lifeline R-201BL	4	$1,106	$174	($286)	18.6%	$14.48
Residential Lifeline 06-201BF	4	$1,124	$237	($268)	26.7%	$19.73
General Service	35,631	$2,676	$200		8.1%	$16.70
SGS Time of Use	1,141	$2,608	$233	($67)	9.8%	$19.40
General Service R-10 Municipal	828	$2,676	$578	$0	27.6%	$48.17
Mobile Home Park Service	252	$19,822	$1,457		7.9%	$121.45
Municipal Water Pumping Service	424	$19,174	$2,124		12.5%	$177.01
Municipal Interruptible WP Service	157	$14,543	$2,125	($4,631)	17.1%	$177.08
Medium General Service		$33,906	$2,273		7.2%	$189.44
Medium General Service TOU		$31,448	$2,938	($2,458)	10.3%	$244.87
Large General Service	437	$199,243	$8,802		4.6%	$733.54
Large General Service TOU	128	$176,510	($7,020)	($22,733)	-3.8%	($584.96)
Large Power Service	19	$4,669,915	($68,892)		-1.5%	($5,741.01)
Traffic Signal& Street Light Service	5,900	$2,949	$346		13.3%	$28.82

Exhibit CAJ – R – 3

Tucson Electric Power Company
Summary of Revenues by Customer Class
Present and Proposed Revenues
Test Year Ended June 30, 2015

Line No.	Rate Description	Test Year Net Revenue	Net Increase	Proposed % Increase to Test Year	Adjusted Test Year Revenue	Proposed Dollar Increase	Proposed % Increase to Adjusted Test Year	Proposed Net Revenue
1	**Class Summary**	$	$	%	$	$	%	$
2	Residential	414,300,965	47,742,302	11.5%	399,183,651	62,859,617	15.7%	462,043,268
3	General Service	263,662,971	(12,097,880)	-4.6%	246,740,288	4,824,803	2.0%	251,565,091
4	Large General Service	112,713,124	36,829,146	32.7%	117,113,457	32,428,812	27.7%	149,542,269
5	Large Power Service	136,020,579	(9,945,704)	-7.3%	126,897,725	(822,850)	-0.6%	126,074,875
6	Transmission Service 138kV	0	0	n/a	0	0	n/a	0
7	Lighting	4,772,245	1,218,765	25.5%	4,612,921	1,378,089	29.9%	5,991,010
8	Subtotal	931,469,884	63,746,629	6.8%	894,548,042	100,668,471	11.3%	995,216,513
9	**Other Operating Revenue**	$0		N/A	$0	N/A	N/A	$0
10	**Total**	**$931,469,884**	**$63,746,629**	**6.8%**	**$894,548,042**	**$100,668,471**	**11.3%**	**$995,216,513**

Supporting Schedules
H-2-2

Recap Schedules
A-1

Links
Other Operating Revenues - Revenue Requirement Model

Note:
-1 Transmission Service 138kV is included with Large Power Service to conceal competitively sensitive confidential data.

Tucson Electric Power Company
Comparison of Sales by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

	TEST YEAR UNADJUSTED			SALES ADJUSTMENTS	TEST YEAR ADJUSTED			PROPOSED		
Rate Description	Test Year Basic Service Charges	Test Year Sales (kWh)	Average Per Service Charge	kWh	Basic Service Charges	Adjusted Sales (kWh)	Average Per Service Charge	Basic Service Charges	Proposed Sales (kWh)	Average Per Service Charge
Class Summary										
Residential	4,618,963	3,675,966,286	796	(24,845,354)	4,624,515	3,651,120,932	790	4,624,515	3,651,120,932	790
General Service	461,846	2,133,735,714	4,620	(1,402,844)	462,775	2,132,332,869	4,608	460,923	1,840,615,447	3,993
Large General Service	7,013	1,189,053,400	169,550	(11,891,293)	6,931	1,177,162,108	169,835	8,783	1,468,879,529	167,237
Large Power Service	204	2,021,151,869	9,907,607	0	216	2,021,151,869	9,357,185	216	1,882,455,168	8,715,070
Transmission Service 138kV	0	0	0	0	0	0	0	0	0	0
Lighting	207,259	38,938,160	188	1,936	207,267	38,940,096	188	207,267	38,940,096	188
TOTAL COMPANY	5,295,285	9,058,845,428	1,711	(38,137,554)	5,301,705	9,020,707,874	1,701	5,301,705	8,882,011,173	1,675
Residential Schedules										
TE-R-01	4,179,070	3,280,964,594	785	(17,027,762)	4,184,314	3,263,936,831	780	4,184,314	3,263,936,831	780
TE-201A	138,080	130,588,706	946	(992,712)	138,058	129,595,994	939	138,058	129,595,994	939
TE-201B	7,903	8,666,134	1,097	(270,031)	7,755	8,396,104	1,083	7,755	8,396,104	1,083
TE-R80	98,375	110,682,540	1,125	(2,373,544)	96,994	108,308,996	1,117	96,994	108,308,996	1,117
TE-R8	754	579,737	769	643,017	1,368	1,222,754	894	1,368	1,222,754	894
TE-R01BC	13,711	11,172,024	815	231,296	14,020	11,403,320	813	14,020	11,403,320	813
Lifeline Rate Schedules										
TE4-01	6,104	3,418,618	560	(222,520)	5,794	3,196,098	552	5,794	3,196,098	552
TE4-21	36	34,185	950	(779)	36	33,406	928	36	33,406	928
TE4-70	72	59,862	831	(941)	72	58,921	818	72	58,921	818
TE5-01	14,084	9,286,821	659	(372,346)	13,698	8,914,475	651	13,698	8,914,475	651
TE5-21	22	25,179	1,145	(10,460)	13	14,719	1,132	13	14,719	1,132
TE5-70	138	94,379	684	(4,851)	134	89,528	669	134	89,528	669
TE6-01	84,662	61,762,560	730	(8,710,908)	74,767	53,051,652	710	74,767	53,051,652	710
TE6-21	228	262,501	1,151	(31,382)	208	231,119	1,112	208	231,119	1,112
TE6-70	839	782,644	933	(170,654)	683	611,990	896	683	611,990	896
TE6-201A	3,756	3,376,855	899	(386,675)	3,397	2,990,181	880	3,397	2,990,181	880
TE6-201B	63	46,930	745	(4,083)	60	42,848	714	60	42,848	714
TE8-01	8,307	8,093,719	974	(1,148,089)	7,336	6,945,630	947	7,336	6,945,630	947
TE8-21	84	124,764	1,485	(1,279)	84	123,485	1,470	84	123,485	1,470
TE8-70	225	223,584	994	(21,111)	211	202,473	958	211	202,473	958
TE8-201A	137	189,352	1,382	(39,071)	112	150,281	1,346	112	150,281	1,346
TE6-01BC	223	159,842	717	(22,220)	196	137,622	701	196	137,622	701
TE-R-01LL	59,739	39,538,976	662	9,350,601	72,257	48,889,577	677	72,257	48,889,577	677
TE-R01LB	149	123,563	829	15,799	166	139,362	838	166	139,362	838
TE-201AL	1,399	1,205,658	862	457,541	1,884	1,663,199	883	1,884	1,663,199	883
TE-201BL	20	27,399	1,370	30,026	40	57,425	1,454	40	57,425	1,454
TE-R80LL	767	625,652	816	76,511	846	702,163	830	846	702,163	830
TE-R8LL	16	11,669	729	(890)	13	10,779	808	13	10,779	808
Residential Unbilled		3,837,839								

Tucson Electric Power Company
Comparison of Sales by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

	TEST YEAR UNADJUSTED			SALES ADJUSTMENTS	TEST YEAR ADJUSTED			PROPOSED		
Rate Description	Test Year Basic Service Charges	Test Year Sales (kWh)	Average Per Service Charge	kWh	Basic Service Charges	Adjusted Sales (kWh)	Average Per Service Charge	Basic Service Charges	Proposed Sales (kWh)	Average Per Service Charge
General Service										
TE-GS10	426,132	1,700,811,779	3,991	10,550,412	427,562	1,711,362,191	4,003	384,015	602,159,416	1,568
TE-GS11	3,580	48,768,661	13,623	(2,197,623)	3,451	46,571,038	13,495	3,451	46,571,038	13,495
TE-GS76	14,274	175,721,877	12,311	(2,109,763)	14,046	173,612,114	12,360	8,917	30,031,910	3,368
TE-G10BC	383	4,734,474	12,362	76,198	389	4,810,672	12,361	305	515,997	1,692
TE-GSM10	9,837	67,460,308	6,858	(827,799)	9,723	66,632,509	6,853	8,047	22,547,155	2,802
TE-G10MBC	526	27,240,424	51,788	(112,154)	524	27,128,270	51,785	0	0	0
TE-GS43	7,114	102,037,299	14,343	178,775	7,081	102,216,075	14,436	7,081	102,216,075	14,436
TE-MGS				0				43,502	890,563,735	
TE-MGSTOU				0				5,160	130,716,715	
TE-MGSBC								446	15,293,406	
General Service Unbilled		6,960,891								
Large General Service										
TE-LGS13	5,312	859,436,643	161,792	(4,638,491)	5,279	854,798,152	161,915	6,999	1,117,522,546	159,658
TE-LG85	1,606	310,229,617	193,169	(9,593,839)	1,556	300,635,778	193,249	1,525	313,499,267	205,594
TE-L13BC	95	21,576,660	227,123	151,518	96	21,728,178	225,812	259	37,857,717	146,221
Large General Service Unbilled		(2,189,520)								
Large Power Service										
TE-LLP14	26	139,880,570	5,380,022	(5,790,325)	24	134,090,245	5,587,094	0	0	0
Special	0	28,794,874	2,399,573	(28,794,874)	0	0	0	0	0	0
Large Power Service TOU	178	1,854,388,905	10,417,915	32,672,719	192	1,887,061,624	9,828,446	216	1,882,455,168	8,715,070
Large Power Service Unbilled		(1,912,480)								
Transmission Service 138kV										
TE-T138kV	0	0	0	N/A	0	0	0	0	0	#DIV/0!
Lighting										
TE-P41	9,104	22,615,813	2,484	207,661	9,096	22,823,474	2,509	9,096	22,823,474	2,509
TE-P47	6,758	8,545,881	1,265	102,017	6,774	8,647,898	1,277	6,774	8,647,898	1,277
TE-R51 + TE-R51A	17,636	672,153	38	(3,839)	17,636	668,314	38	17,636	668,314	38
TE-C52 & 52A	135,544	4,930,591	36	(3,891)	135,544	4,926,700	36	135,544	4,926,700	36
TE-P50	38,217	1,852,451	48	21,259	38,217	1,873,710	49	38,217	1,873,710	49
Lighting Unbilled		321,271								

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

		Test Year Revenue		Revenue Adjustments	Adjusted Test Year Revenue Plus Fuel Proforma		Proposed Revenues		Proposed Increase to Test Year Revenue		Proposed Increase to Adjusted Revenue	
Distribution Id	Rate Description	Margin ($)	Fuel ($)	$	Margin ($)	Fuel ($)	Margin ($)	Fuel ($)	$	%	$	%
	Class Summary											
	Residential	276,745,450	137,555,516	(15,117,315)	275,887,975	123,295,676	338,747,592	123,295,676	47,742,302	0	62,859,617	15.7%
	General Service	184,360,130	79,302,841	(16,922,683)	184,448,887	62,291,401	189,231,531	62,333,560	(12,097,880)	(0)	4,824,803	2.0%
	Large General Service	68,297,227	44,415,897	4,400,334	68,460,569	48,652,888	100,889,381	48,652,888	36,829,146	0	32,428,812	27.7%
	Large Power Service	73,191,548	62,829,031	(9,122,854)	73,302,768	53,594,957	72,479,918	53,594,957	(9,945,704)	(0)	(822,850)	-0.6%
	Transmission Service Rate	0	0	0	0	0	0	0	0	N/A	0	N/A
	Lighting	3,303,187	1,469,057	(159,324)	3,298,783	1,314,137	4,676,872	1,314,137	1,218,765	0	1,378,089	29.9%
	TOTAL COMPANY	605,897,543	325,572,341	(36,921,842)	605,398,982	289,149,060	706,025,294	289,191,218	63,746,629	0	100,668,471	11.3%
	Residential Schedules											
5000	TE-R-01	251,807,725	122,674,283	(11,196,036)	250,967,738	112,318,234	305,375,073	112,318,234	43,211,299	0	54,407,335	14.98%
5004	TE-201A	8,979,804	4,880,819	(1,386,828)	8,923,159	3,550,637	11,791,366	3,550,637	1,481,379	0	2,868,207	22.99%
5005	TE-201B	0	298,135	359,693	449,399	208,429	751,353	208,429	661,646	2	301,953	45.90%
5040	TE-R80	6,748,591	3,807,714	(554,141)	6,629,150	3,373,014	9,670,031	3,373,014	2,486,740	0	3,040,881	30.40%
5042	TE-R8	39,021	17,725	61,479	84,240	33,985	111,700	33,985	88,939	2	27,461	23.23%
5060	TE-R01BC	851,640	373,656	11,931	870,889	366,338	1,056,697	366,338	197,739	0	185,808	15.02%
	Lifeline Rate Schedules											
5002	TE4-01	187,990	89,256	(47,137)	175,417	54,692	190,972	54,692	(31,582)	(0)	15,555	6.76%
5008	TE4-21	1,612	1,028	(228)	1,567	844	2,254	844	458	0	687	28.47%
5009	TE4-70	3,139	1,644	(370)	3,077	1,335	3,877	1,335	429	0	800	18.13%
5010	TE5-01	571,226	277,370	(58,314)	547,423	242,859	706,207	242,859	100,470	0	158,784	20.09%
5012	TE5-21	1,242	807	(845)	738	466	1,169	466	(414)	(0)	430	35.73%
5013	TE5-70	5,466	2,786	(685)	5,162	2,405	7,150	2,405	1,304	0	1,988	26.28%
5016	TE6-01	3,730,879	1,828,957	(875,787)	3,203,498	1,480,551	4,216,211	1,480,551	136,926	0	1,012,713	21.62%
5017	TE6-21	12,269	7,969	(3,324)	10,790	6,124	16,121	6,124	2,007	0	5,331	31.52%
5022	TE6-70	43,687	23,012	(14,790)	34,101	17,809	48,611	17,809	(279)	(0)	14,510	27.95%
5023	TE6-201A	169,675	102,562	(56,129)	149,713	66,395	236,166	66,395	30,324	0	86,452	40.00%
5024	TE6-201B	2,038	1,298	(616)	1,840	880	3,430	880	974	0	1,590	58.47%
5026	TE8-01	386,096	196,771	(103,911)	329,967	148,989	424,143	148,989	(9,734)	(0)	94,177	19.66%
5027	TE8-21	4,771	3,238	53	4,722	3,339	8,435	3,339	3,765	0	3,712	46.05%
5028	TE8-70	9,942	5,317	(2,098)	8,887	4,274	12,448	4,274	1,463	0	3,561	27.06%
5029	TE8-201A	7,659	4,895	(3,478)	6,028	3,047	10,788	3,047	1,281	0	4,760	52.45%
5032	TE6-01BC	9,626	4,699	(2,226)	8,290	3,810	10,940	3,810	425	0	2,651	21.91%
5033	TE-R-01LL	2,674,986	1,311,018	677,158	3,316,275	1,346,887	3,888,372	1,346,887	1,249,255	0	572,097	12.27%
5034	TE-R01LB	8,347	4,190	914	9,438	4,013	10,981	4,013	2,457	0	1,543	11.47%
5035	TE-201AL	74,180	40,970	24,330	102,638	36,842	131,498	36,842	53,190	0	28,860	20.69%
5036	TE-201BL	1,323	877	1,794	2,746	1,247	4,633	1,247	3,680	2	1,886	47.23%
5041	TE-R80LL	35,808	19,187	3,389	40,408	17,976	56,105	17,976	19,086	0	15,697	26.89%
5043	TE-R8LL	707	334	(114)	674	253	863	253	75	0	189	20.34%
	Residential Unbilled	376,000	1,575,000		Unbilled is included above		0	0	0	N/A	0	N/A

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

		Test Year Revenue		Revenue Adjustments	Adjusted Test Year Revenue Plus Fuel Proforma		Proposed Revenues		Proposed Increase to Test Year Revenue		Proposed Increase to Adjusted Revenue	
Distribution Id	**Rate Description**	Margin ($)	Fuel ($)	$	Margin ($)	Fuel ($)	Margin ($)	Fuel ($)	$	%	$	%
	General Service											
5200	TE-GS10	153,865,268	63,703,857	(41,922,161)	155,070,441	20,576,522	66,743,566	20,576,522	(130,249,036)	(1)	(88,326,876)	-50.29%
5201	TE-GS11	3,524,955	1,819,452	(388,244)	3,367,260	1,588,903	4,045,354	1,588,903	289,850	0	678,094	13.68%
5213	TE-GS76	13,847,635	6,008,984	(5,226,699)	13,712,568	917,352	3,075,758	917,352	(15,863,509)	(1)	(10,636,810)	-72.71%
5225	TE-G10BC	420,954	145,939	(30,793)	427,972	108,128	56,315	108,128	(402,450)	(1)	(371,656)	-69.33%
5230	TE-GSM10	5,066,210	2,108,192	(1,401,797)	5,004,641	767,964	2,363,955	767,964	(4,042,483)	(1)	(2,640,686)	-45.75%
5231	TE-G10MBC	2,009,095	821,670	(454,729)	1,998,695	377,341	0	377,341	(2,453,424)	(1)	(1,998,695)	-84.12%
5240	TE-GS43	4,858,013	3,651,746	(322,995)	4,867,310	3,319,455	6,734,062	3,319,455	1,543,758	0	1,866,752	22.80%
XXXX	TE-MGS	0	0	30,395,450	0	30,395,450	92,002,382	30,437,609	122,439,991	N/A	92,044,541	N/A
XXXX	TE-MGSTOU	0	0	3,999,655	0	3,999,655	12,634,344	3,999,655	16,633,999	N/A	12,634,344	N/A
XXXX	TE-MGSBC					240,630	1,575,795	240,630	1,816,425	N/A	1,575,795	N/A
	General Service Unbilled	768,000	1,043,000		Unbilled is included above		0	0	0	N/A	0	N/A
	Large General Service											
5300	TE-LGS13	52,178,293	32,183,205	5,683,109	51,915,256	38,129,351	82,238,575	38,129,351	36,006,428	0	30,323,319	33.68%
5305	TE-LG85	15,878,358	10,579,443	(1,513,857)	15,386,190	9,557,754	15,912,213	9,557,754	(987,834)	(0)	526,023	2.11%
5322	TE-L13BC	1,151,576	720,248	253,082	1,159,123	965,783	2,738,593	965,783	1,832,552	1	1,579,470	74.33%
	Large General Service Unbilled	(911,000)	933,000		Unbilled is included above		0	0	0	N/A	0	N/A
	Large Power Service											
5301	TE-LLP14	6,004,077	4,773,275	(5,019,433)	5,757,919	0	0	0	0	0	N/A	N/A
5308	Special	882,693	777,092	(1,659,785)	0	0	0	0	0	0	N/A	N/A
5309/5350	Large Power Service TOU	66,309,779	57,243,663	(2,413,637)	67,544,848	53,594,957	72,479,918	53,594,957	2,521,433	0	4,935,069	4.07%
	Industrial Unbilled	(5,000)	35,000		Unbilled is included above		0	0	0	N/A	0	N/A
	Transmission Service 138kV											
XXXX	TE-T138kV	0	0	0	0	0	0	0	0	N/A	0	N/A
	Lighting											
5400	TE-P41	1,076,513	846,600	(65,611)	1,086,397	771,104	1,485,808	771,104	333,799	0	399,411	21.50%
5401	TE-P47	406,784	319,997	(22,717)	411,640	292,424	562,978	292,424	128,622	0	151,338	21.49%
5011	TE-R51 + TE-R51A	145,242	25,118	(2,571)	145,228	22,560	211,884	22,560	64,085	0	66,657	39.73%
5203	TE-C52 & 52A	1,293,110	184,528	(21,022)	1,290,979	165,636	1,884,419	165,636	572,418	0	593,440	40.74%
5402	TE-P50	364,539	69,816	(7,403)	364,539	62,413	531,783	62,413	159,841	0	167,244	39.17%
	Lighting Unbilled	17,000	23,000		Unbilled is included above		0	0	0	N/A	0	N/A

Tucson Electric Power Company
Comparison of Present and Proposed Rates
Test Period Ended June 30, 2015

Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
TE-R-01	**Residential Service**				
	Basic Service Charge Single Phase Per Mo.	$10.00	$17.00	$7.00	70%
	Basic Service Charge Three Phase Per Mo.	$15.00	$22.00	$7.00	47%
	Sum First 500 kWh	$0.056200	$0.061158	$0.004958	9%
	Sum 501-1,000 kWh	$0.067200	$0.083100	$0.015900	24%
	Sum 1,001-3,500 kWh	$0.079800	$0.083100	$0.003300	4%
	Sum>3,500 kWh	$0.088200	$0.083100	-$0.005100	-6%
	Win First 500 kWh	$0.056200	$0.061158	$0.004958	9%
	Win 501-1,000 kWh	$0.065200	$0.083100	$0.017900	27%
	Win 1,001-3,500 kWh	$0.078100	$0.083100	$0.005000	6%
	Win>3,500 kWh	$0.087100	$0.083100	-$0.004000	-5%
	Base Power Summer kWh	$0.035111	$0.035868	$0.000757	2%
	Base Power Winter kWh	$0.031532	$0.032537	$0.001005	3%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
	Solar Block Rate for Residential Electric Service Rate R-01	$0.053463	$0.054412	$0.000949	2%
TE-RXXX	**Residential Service Demand**				
	Basic Service Charge Per Month	N/M	$17.00	N/M	N/M
	Demand 0-7 kW	N/M	$7.40	N/M	N/M
	Demand > 7 kW	N/M	$11.90	N/M	N/M
	Sum kWh	N/M	$0.024920	N/M	N/M
	Win kWh	N/M	$0.024920	N/M	N/M
	Base Power Summer kWh	N/M	$0.035868	N/M	N/M
	Base Power Winter kWh	N/M	$0.032537	N/M	N/M
	PPFAC Charge	N/M	$0.000000	N/M	N/M
TE-201A	**Special Residential Electric Service**				
	Basic Service Charge	$10.00	$17.00	$7.00	70%
	Sum First 500 kWh	$0.050600	$0.061158	$0.010558	21%
	Sum 501-1,000 kWh	$0.060500	$0.083100	$0.022600	37%
	Sum 1,001-3,500 kWh	$0.071800	$0.083100	$0.011300	16%
	Sum>3,500 kWh	$0.079400	$0.083100	$0.003700	5%
	Win First 500 kWh	$0.050600	$0.061158	$0.010558	21%
	Win 501-1,000 kWh	$0.058700	$0.083100	$0.024400	42%
	Win 1,001-3,500 kWh	$0.070300	$0.083100	$0.012800	18%
	Win>3,500 kWh	$0.078400	$0.083100	$0.004700	6%
	Base Power Summer kWh	$0.035111	$0.028694	-$0.006417	-18%
	Base Power Winter kWh	$0.031532	$0.026030	-$0.005502	-17%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
TE-201B	**Special Residential Electric Service Time of Use**				
	Basic Service Charge	$11.50	$17.00	$5.50	48%
	Sum On-peak First 500 kWh	$0.056800	$0.061158	$0.004358	8%
	Sum On-peak 501-1,000 kWh	$0.056800	$0.083100	$0.026300	46%
	Sum On-peak1,001-3,500 kWh	$0.056800	$0.083100	$0.026300	46%
	Sum On-peak >3,500 kWh	$0.056800	$0.083100	$0.026300	46%
	Sum Off-peak First 500 kWh	$0.044000	$0.061158	$0.017158	39%
	Sum Off-peak 501-1,000 kWh	$0.044000	$0.083100	$0.039100	89%
	Sum Off-peak1,001-3,500 kWh	$0.044000	$0.083100	$0.039100	89%
	Sum Off-peak >3,500 kWh	$0.044000	$0.083100	$0.039100	89%
	Win On-peak First 500 kWh	$0.048300	$0.061158	$0.012858	27%
	Win On-peak 501-1,000 kWh	$0.048300	$0.083100	$0.034800	72%
	Win On-peak1,001-3,500 kWh	$0.048300	$0.083100	$0.034800	72%
	Win On-peak >3,500 kWh	$0.048300	$0.083100	$0.034800	72%
	Win Off-peak First 500 kWh	$0.035500	$0.061158	$0.025658	72%
	Win Off-peak 501-1,000 kWh	$0.035500	$0.083100	$0.047600	134%
	Win Off-peak1,001-3,500 kWh	$0.035500	$0.083100	$0.047600	134%
	Win Off-peak >3,500 kWh	$0.035500	$0.083100	$0.047600	134%
	Base Power Summer On-Peak kWh	$0.050669	$0.041328	-$0.009341	-18%
	Base Power Summer Off-Peak kWh	$0.026679	$0.021400	-$0.005279	-20%
	Base Power Winter On-peak kWh	$0.032893	$0.027114	-$0.005779	-18%
	Base Power Winter Off-peak kWh	$0.027092	$0.022474	-$0.004618	-17%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M

Tucson Electric Power Company
Comparison of Present and Proposed Rates
Test Period Ended June 30, 2015

Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
TE-R80	**Residential Time of Use**				
	Basic Service Charge	$11.50	$17.00	$5.50	48%
	Sum On-peak First 500 kWh	$0.066800	$0.061158	-$0.005642	-8%
	Sum On-peak 501-1,000 kWh	$0.066800	$0.083100	$0.016300	24%
	Sum On-peak1,001-3,500 kWh	$0.066800	$0.083100	$0.016300	24%
	Sum On-peak >3,500 kWh	$0.066800	$0.083100	$0.016300	24%
	Sum Off-peak First 500 kWh	$0.051800	$0.061158	$0.009358	18%
	Sum Off-peak 501-1,000 kWh	$0.051800	$0.083100	$0.031300	60%
	Sum Off-peak1,001-3,500 kWh	$0.051800	$0.083100	$0.031300	60%
	Sum Off-peak >3,500 kWh	$0.051800	$0.083100	$0.031300	60%
	Win On-peak First 500 kWh	$0.056800	$0.061158	$0.004358	8%
	Win On-peak 501-1,000 kWh	$0.056800	$0.083100	$0.026300	46%
	Win On-peak1,001-3,500 kWh	$0.056800	$0.083100	$0.026300	46%
	Win On-peak >3,500 kWh	$0.056800	$0.083100	$0.026300	46%
	Win Off-peak First 500 kWh	$0.041800	$0.061158	$0.019358	46%
	Win Off-peak 501-1,000 kWh	$0.041800	$0.083100	$0.041300	99%
	Win Off-peak1,001-3,500 kWh	$0.041800	$0.083100	$0.041300	99%
	Win Off-peak >3,500 kWh	$0.041800	$0.083100	$0.041300	99%
	Base Power Summer On-Peak kWh	$0.050669	$0.051660	$0.000991	2%
	Base Power Summer Off-Peak kWh	$0.026679	$0.026750	$0.000071	0%
	Base Power Winter On-peak kWh	$0.032893	$0.033893	$0.001000	3%
	Base Power Winter Off-peak kWh	$0.027092	$0.028092	$0.001000	4%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
TE-RXXX	**Residential Demand Time of Use**				
	Basic Service Charge Per Month	N/M	$17.00	N/M	N/M
	Demand 0-7 kW	N/M	$7.40	N/M	N/M
	Demand > 7 kW	N/M	$11.90	N/M	N/M
	Sum On-peak kWh	N/M	$0.024920	N/M	N/M
	Sum Off-peak kWh	N/M	$0.024920	N/M	N/M
	Win On-peak kWh	N/M	$0.024920	N/M	N/M
	Win Off-peak kWh	N/M	$0.024920	N/M	N/M
	Base Power Summer On-Peak kWh	N/M	$0.051660	N/M	N/M
	Base Power Summer Off-Peak kWh	N/M	$0.026750	N/M	N/M
	Base Power Winter On-peak kWh	N/M	$0.033893	N/M	N/M
	Base Power Winter Off-peak kWh	N/M	$0.028092	N/M	N/M
	PPFAC Charge	N/M	$0.000000	N/M	N/M
TE-R8	**Residential Time of Use Super Peak**				
	Basic Service Charge	$11.50	$17.00	$5.50	48%
	Sum On-peak First 500 kWh	$0.097100	$0.061158	-$0.035942	-37%
	Sum On-peak 501-1,000 kWh	$0.097100	$0.083100	-$0.014000	-14%
	Sum On-peak1,001-3,500 kWh	$0.120100	$0.083100	-$0.037000	-31%
	Sum On-peak >3,500 kWh	$0.120100	$0.083100	-$0.037000	-31%
	Sum Off-peak First 500 kWh	$0.048500	$0.061158	$0.012658	26%
	Sum Off-peak 501-1,000 kWh	$0.048500	$0.083100	$0.034600	71%
	Sum Off-peak1,001-3,500 kWh	$0.071500	$0.083100	$0.011600	16%
	Sum Off-peak >3,500 kWh	$0.071500	$0.083100	$0.011600	16%
	Win On-peak First 500 kWh	$0.089100	$0.061158	-$0.027942	-31%
	Win On-peak 501-1,000 kWh	$0.089100	$0.083100	-$0.006000	-7%
	Win On-peak1,001-3,500 kWh	$0.112100	$0.083100	-$0.029000	-26%
	Win On-peak >3,500 kWh	$0.112100	$0.083100	-$0.029000	-26%
	Win Off-peak First 500 kWh	$0.038500	$0.061158	$0.022658	59%
	Win Off-peak 501-1,000 kWh	$0.038500	$0.083100	$0.044600	116%
	Win Off-peak1,001-3,500 kWh	$0.061500	$0.083100	$0.021600	35%
	Win Off-peak >3,500 kWh	$0.061500	$0.083100	$0.021600	35%
	Base Power Summer On-Peak kWh	$0.080100	$0.081060	$0.000960	1%
	Base Power Summer Off-Peak kWh	$0.022200	$0.022750	$0.000550	2%
	Base Power Winter On-peak kWh	$0.040200	$0.041293	$0.001093	3%
	Base Power Winter Off-peak kWh	$0.020500	$0.021492	$0.000992	5%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M

Tucson Electric Power Company
Comparison of Present and Proposed Rates
Test Period Ended June 30, 2015

Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
TE-R01BC	**Residential Service R-01 Bright Community Solar**				
	Basic Service Charge Single Phase	$10.00	$17.00	$7.00	70%
	Sum First 500 kWh	$0.056200	$0.061158	$0.004958	9%
	Sum 501-1,000 kWh	$0.067200	$0.083100	$0.015900	24%
	Sum 1,001-3,500 kWh	$0.079800	$0.083100	$0.003300	4%
	Sum>3,500 kWh	$0.088200	$0.083100	-$0.005100	-6%
	Win First 500 kWh	$0.056200	$0.061158	$0.004958	9%
	Win 501-1,000 kWh	$0.065200	$0.083100	$0.017900	27%
	Win 1,001-3,500 kWh	$0.078100	$0.083100	$0.005000	6%
	Win>3,500 kWh	$0.087100	$0.083100	-$0.004000	-5%
	Base Power Summer kWh	$0.035111	$0.035868	$0.000757	2%
	Base Power Winter kWh	$0.031532	$0.032537	$0.001005	3%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
TE4-01	**Lifeline Residential Service Standard (Frozen 1996 - R-04-01F Senior % Discount)**				
	Basic Service Charge Per Month	$6.90	$17.00	$10.10	146%
	Sum First 500 kWh	$0.061100	$0.061158	$0.000058	0%
	Sum 501-1,000 kWh	$0.061100	$0.083100	$0.022000	36%
	Sum >1,000 kWh	$0.061100	$0.083100	$0.022000	36%
	Win First 500 kWh	$0.057000	$0.061158	$0.004158	7%
	Win 501-1,000 kWh	$0.057000	$0.083100	$0.026100	46%
	Win >1,000 kWh	$0.057000	$0.083100	$0.026100	46%
	Base Power Summer kWh	$0.033198	$0.035868	$0.002670	8%
	Base Power Winter kWh	$0.025698	$0.032537	$0.006839	27%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
TE4-21	**Lifeline Residential Time of Use (Frozen 1996 - Senior % Discount)**				
	Basic Service Charge Per Month	$8.86	$17.00	$8.14	92%
	Sum On-Peak First 500 kWh	$0.078800	$0.061158	-$0.017642	-22%
	Sum On-Peak 501-1,000 kWh	$0.078800	$0.083100	$0.004300	5%
	Sum On-Peak >1,000 kWh	$0.078800	$0.083100	$0.004300	5%
	Sum Off-Peak First 500 kWh	$0.030100	$0.061158	$0.031058	103%
	Sum Off-Peak 501-1,000 kWh	$0.030100	$0.083100	$0.053000	176%
	Sum Off-Peak >1,000 kWh	$0.030100	$0.083100	$0.053000	176%
	Win On-Peak First 500 kWh	$0.065200	$0.061158	-$0.004042	-6%
	Win On-Peak 501-1,000 kWh	$0.065200	$0.083100	$0.017900	27%
	Win On-Peak >1,000 kWh	$0.065200	$0.083100	$0.017900	27%
	Win Off-Peak First 500 kWh	$0.033000	$0.061158	$0.028158	85%
	Win Off-Peak 501-1,000 kWh	$0.033000	$0.083100	$0.050100	152%
	Win Off-Peak >1,000 kWh	$0.033000	$0.083100	$0.050100	152%
	Base Power Summer On-Peak kWh	$0.053198	$0.051660	-$0.001538	-3%
	Base Power Summer Off-Peak kWh	$0.023198	$0.026750	$0.003552	15%
	Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
	Base Power Winter Off-peak kWh	$0.020698	$0.028092	$0.007394	36%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M

Tucson Electric Power Company
Comparison of Present and Proposed Rates
Test Period Ended June 30, 2015

Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
TE4-70	**Lifeline Residential Time of Use (Frozen 1996 - Senior % Discount)**				
	Basic Service Charge Per Month	$8.78	$17.00	$8.22	94%
	Sum On-Peak First 500 kWh	$0.139300	$0.061158	-$0.078142	-56%
	Sum On-Peak 501-1,000 kWh	$0.139300	$0.083100	-$0.056200	-40%
	Sum On-Peak >1,000 kWh	$0.139300	$0.083100	-$0.056200	-40%
	Sum Shldr-Peak First 500 kWh	$0.074000	$0.061158	-$0.012842	-17%
	Sum Shldr-Peak 501-1,000 kWh	$0.074000	$0.083100	$0.009100	12%
	Sum Shldr-Peak >1,000 kWh	$0.074000	$0.083100	$0.009100	12%
	Sum Off-Peak First 500 kWh	$0.037900	$0.061158	$0.023258	61%
	Sum Off-Peak 501-1,000 kWh	$0.037900	$0.083100	$0.045200	119%
	Sum Off-Peak >1,000 kWh	$0.037900	$0.083100	$0.045200	119%
	Win On-Peak First 500 kWh	$0.092500	$0.061158	-$0.031342	-34%
	Win On-Peak 501-1,000 kWh	$0.092500	$0.083100	-$0.009400	-10%
	Win On-Peak >1,000 kWh	$0.092500	$0.083100	-$0.009400	-10%
	Win Off-Peak First 500 kWh	$0.024900	$0.061158	$0.036258	146%
	Win Off-Peak 501-1,000 kWh	$0.024900	$0.083100	$0.058200	234%
	Win Off-Peak >1,000 kWh	$0.024900	$0.083100	$0.058200	234%
	Base Power Summer On-Peak kWh	$0.055698	$0.051660	-$0.004038	-7%
	Base Power Summer Shoulder kWh	$0.048198	$0.051660	$0.003462	7%
	Base Power Summer Off-Peak kWh	$0.023198	$0.026750	$0.003552	15%
	Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
	Base Power Winter Off-peak kWh	$0.020698	$0.028092	$0.007394	36%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
TE5-01	**Lifeline Residential Service Standard (Frozen Lifeline % Discount)**				
	Basic Service Charge Per Month	$6.90	$17.00	$10.10	146%
	Sum First 500 kWh	$0.061100	$0.061158	$0.000058	0%
	Sum 501-1,000 kWh	$0.061100	$0.083100	$0.022000	36%
	Sum >1,000 kWh	$0.061100	$0.083100	$0.022000	36%
	Win First 500 kWh	$0.057000	$0.061158	$0.004158	7%
	Win 501-1,000 kWh	$0.057000	$0.083100	$0.026100	46%
	Win >1,000 kWh	$0.057000	$0.083100	$0.026100	46%
	Base Power Summer kWh	$0.033198	$0.035868	$0.002670	8%
	Base Power Winter kWh	$0.025698	$0.032537	$0.006839	27%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
TE5-21	**Residential Time of Use (Frozen Lifeline % Discount)**				
	Basic Service Charge Per Month	$8.86	$17.00	$8.14	92%
	Sum On-Peak First 500 kWh	$0.078800	$0.061158	-$0.017642	-22%
	Sum On-Peak 501-1,000 kWh	$0.078800	$0.083100	$0.004300	5%
	Sum On-Peak >1,000 kWh	$0.078800	$0.083100	$0.004300	5%
	Sum Off-Peak First 500 kWh	$0.030100	$0.061158	$0.031058	103%
	Sum Off-Peak 501-1,000 kWh	$0.030100	$0.083100	$0.053000	176%
	Sum Off-Peak >1,000 kWh	$0.030100	$0.083100	$0.053000	176%
	Win On-Peak First 500 kWh	$0.065200	$0.061158	-$0.004042	-6%
	Win On-Peak 501-1,000 kWh	$0.065200	$0.083100	$0.017900	27%
	Win On-Peak >1,000 kWh	$0.065200	$0.083100	$0.017900	27%
	Win Off-Peak First 500 kWh	$0.033000	$0.061158	$0.028158	85%
	Win Off-Peak 501-1,000 kWh	$0.033000	$0.083100	$0.050100	152%
	Win Off-Peak >1,000 kWh	$0.033000	$0.083100	$0.050100	152%
	Base Power Summer On-Peak kWh	$0.053198	$0.051660	-$0.001538	-3%
	Base Power Summer Off-Peak kWh	$0.023198	$0.026750	$0.003552	15%
	Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
	Base Power Winter Off-peak kWh	$0.020698	$0.028092	$0.007394	36%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M

Tucson Electric Power Company
Comparison of Present and Proposed Rates
Test Period Ended June 30, 2015

Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
TE5-70	**Residential Time of Use (Frozen Lifeline % Discount)**				
	Basic Service Charge Per Month	$8.78	$17.00	$8.22	94%
	Sum On-Peak First 500 kWh	$0.139300	$0.061158	-$0.078142	-56%
	Sum On-Peak 501-1,000 kWh	$0.139300	$0.083100	-$0.056200	-40%
	Sum On-Peak >1,000 kWh	$0.139300	$0.083100	-$0.056200	-40%
	Sum Shldr-Peak First 500 kWh	$0.074000	$0.061158	-$0.012842	-17%
	Sum Shldr-Peak 501-1,000 kWh	$0.074000	$0.083100	$0.009100	12%
	Sum Shldr-Peak >1,000 kWh	$0.074000	$0.083100	$0.009100	12%
	Sum Off-Peak First 500 kWh	$0.037900	$0.061158	$0.023258	61%
	Sum Off-Peak 501-1,000 kWh	$0.037900	$0.083100	$0.045200	119%
	Sum Off-Peak >1,000 kWh	$0.037900	$0.083100	$0.045200	119%
	Win On-Peak First 500 kWh	$0.092500	$0.061158	-$0.031342	-34%
	Win On-Peak 501-1,000 kWh	$0.092500	$0.083100	-$0.009400	-10%
	Win On-Peak >1,000 kWh	$0.092500	$0.083100	-$0.009400	-10%
	Win Off-Peak First 500 kWh	$0.024900	$0.061158	$0.036258	146%
	Win Off-Peak 501-1,000 kWh	$0.024900	$0.083100	$0.058200	234%
	Win Off-Peak >1,000 kWh	$0.024900	$0.083100	$0.058200	234%
	Base Power Summer On-Peak kWh	$0.055698	$0.051660	-$0.004038	-7%
	Base Power Summer Shoulder kWh	$0.048198	$0.051660	$0.003462	7%
	Base Power Summer Off-Peak kWh	$0.023198	$0.026750	$0.003552	15%
	Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
	Base Power Winter Off-peak kWh	$0.020698	$0.028092	$0.007394	36%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
TE6-01	**Residential Service Standard (Frozen Lifeline Flat Discount)**				
	Basic Service Charge Per Month	$6.90	$17.00	$10.10	146%
	Sum First 500 kWh	$0.061100	$0.061158	$0.000058	0%
	Sum 501-1,000 kWh	$0.061100	$0.083100	$0.022000	36%
	Sum >1,000 kWh	$0.061100	$0.083100	$0.022000	36%
	Win First 500 kWh	$0.057000	$0.061158	$0.004158	7%
	Win 501-1,000 kWh	$0.057000	$0.083100	$0.026100	46%
	Win >1,000 kWh	$0.057000	$0.083100	$0.026100	46%
	Base Power Summer kWh	$0.033198	$0.035868	$0.002670	8%
	Base Power Winter kWh	$0.025698	$0.032537	$0.006839	27%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
TE6-21	**Residential Time of Use (Frozen Lifeline Flat Discount)**				
	Basic Service Charge Per Month	$8.86	$17.00	$8.14	92%
	Sum On-Peak First 500 kWh	$0.078800	$0.061158	-$0.017642	-22%
	Sum On-Peak 501-1,000 kWh	$0.078800	$0.083100	$0.004300	5%
	Sum On-Peak >1,000 kWh	$0.078800	$0.083100	$0.004300	5%
	Sum Off-Peak First 500 kWh	$0.030100	$0.061158	$0.031058	103%
	Sum Off-Peak 501-1,000 kWh	$0.030100	$0.083100	$0.053000	176%
	Sum Off-Peak >1,000 kWh	$0.030100	$0.083100	$0.053000	176%
	Win On-Peak First 500 kWh	$0.065200	$0.061158	-$0.004042	-6%
	Win On-Peak 501-1,000 kWh	$0.065200	$0.083100	$0.017900	27%
	Win On-Peak >1,000 kWh	$0.065200	$0.083100	$0.017900	27%
	Win Off-Peak First 500 kWh	$0.033000	$0.061158	$0.028158	85%
	Win Off-Peak 501-1,000 kWh	$0.033000	$0.083100	$0.050100	152%
	Win Off-Peak >1,000 kWh	$0.033000	$0.083100	$0.050100	152%
	Base Power Summer On-Peak kWh	$0.053198	$0.051660	-$0.001538	-3%
	Base Power Summer Off-Peak kWh	$0.023198	$0.026750	$0.003552	15%
	Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
	Base Power Winter Off-peak kWh	$0.020698	$0.028092	$0.007394	36%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M

Tucson Electric Power Company
Comparison of Present and Proposed Rates
Test Period Ended June 30, 2015

Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
TE6-70	**Residential Time of Use (Frozen Lifeline Flat Discount)**				
	Basic Service Charge Per Month	$8.78	$17.00	$8.22	94%
	Sum On-Peak First 500 kWh	$0.139300	$0.061158	-$0.078142	-56%
	Sum On-Peak 501-1,000 kWh	$0.139300	$0.083100	-$0.056200	-40%
	Sum On-Peak >1,000 kWh	$0.139300	$0.083100	-$0.056200	-40%
	Sum Shldr-Peak First 500 kWh	$0.074000	$0.061158	-$0.012842	-17%
	Sum Shldr-Peak 501-1,000 kWh	$0.074000	$0.083100	$0.009100	12%
	Sum Shldr-Peak >1,000 kWh	$0.074000	$0.083100	$0.009100	12%
	Sum Off-Peak First 500 kWh	$0.037900	$0.061158	$0.023258	61%
	Sum Off-Peak 501-1,000 kWh	$0.037900	$0.083100	$0.045200	119%
	Sum Off-Peak >1,000 kWh	$0.037900	$0.083100	$0.045200	119%
	Win On-Peak First 500 kWh	$0.092500	$0.061158	-$0.031342	-34%
	Win On-Peak 501-1,000 kWh	$0.092500	$0.083100	-$0.009400	-10%
	Win On-Peak >1,000 kWh	$0.092500	$0.083100	-$0.009400	-10%
	Win Off-Peak First 500 kWh	$0.024900	$0.061158	$0.036258	146%
	Win Off-Peak 501-1,000 kWh	$0.024900	$0.083100	$0.058200	234%
	Win Off-Peak >1,000 kWh	$0.024900	$0.083100	$0.058200	234%
	Base Power Summer On-Peak kWh	$0.055698	$0.051660	-$0.004038	-7%
	Base Power Summer Shoulder kWh	$0.048198	$0.051660	$0.003462	7%
	Base Power Summer Off-Peak kWh	$0.023198	$0.026750	$0.003552	15%
	Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
	Base Power Winter Off-peak kWh	$0.020698	$0.028092	$0.007394	36%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
TE6-201A	**Special Residential Service (Frozen Lifeline Flat Discount)**				
	Basic Service Charge Per Month	$6.90	$17.00	$10.10	146%
	Mid Sum First 500 kWh	$0.061100	$0.061158	$0.000058	0%
	Mid Sum 501-1,000 kWh	$0.061100	$0.083100	$0.022000	36%
	Mid Sum >1,000 kWh	$0.061100	$0.083100	$0.022000	36%
	Remain Sum First 500 kWh	$0.043600	$0.061158	$0.017558	40%
	Remain Sum 501-1,000 kWh	$0.043600	$0.083100	$0.039500	91%
	Remain Sum >1,000 kWh	$0.043600	$0.083100	$0.039500	91%
	Win First 500 kWh	$0.041300	$0.061158	$0.019858	48%
	Win 501-1,000 kWh	$0.041300	$0.083100	$0.041800	101%
	Win >1,000 kWh	$0.041300	$0.083100	$0.041800	101%
	Base Power Mid Summer kWh	$0.033198	$0.028694	-$0.004504	-14%
	Base Power Remaining Summer kWh	$0.033198	$0.000000	-$0.033198	-100%
	Base Power Winter kWh	$0.027198	$0.026030	-$0.001168	-4%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M

Tucson Electric Power Company
Comparison of Present and Proposed Rates
Test Period Ended June 30, 2015

Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
TE6-201B	**Special Residential Service Time of Use (Frozen Lifeline Flat Discount)**				
	Basic Service Charge Per Month	$8.78	$17.00	$8.22	94%
	Mid Sum On-Peak First 500 kWh	$0.136900	$0.061158	-$0.075742	-55%
	Mid Sum On-Peak 501-1,000 kWh	$0.136900	$0.083100	-$0.053800	-39%
	Mid Sum On-Peak >1,000 kWh	$0.136900	$0.083100	-$0.053800	-39%
	Mid Sum Shlder-Peak First 500 kWh	$0.074700	$0.061158	-$0.013542	-18%
	Mid Sum Shldr-Peak 501-1,000 kWh	$0.074700	$0.083100	$0.008400	11%
	Mid Sum Shldr-Peak >1,000 kWh	$0.074700	$0.083100	$0.008400	11%
	Mid Sum Off-Peak First 500 kWh	$0.038300	$0.061158	$0.022858	60%
	Mid Sum Off-Peak 501-1,000 kWh	$0.038300	$0.083100	$0.044800	117%
	Mid Sum Off-Peak >1,000 kWh	$0.038300	$0.083100	$0.044800	117%
	Remain Sum On-Peak First 500 kWh	$0.099500	$0.000000	-$0.099500	-100%
	Remain Sum On-Peak 501-1,000 kWh	$0.099500	$0.000000	-$0.099500	-100%
	Remain Sum On-Peak >1,000 kWh	$0.099500	$0.000000	-$0.099500	-100%
	Remain Sum Shlder-Peak First 500 kWh	$0.048600	$0.000000	-$0.048600	-100%
	Remain Sum Shldr-Peak 501-1,000 kWh	$0.048600	$0.000000	-$0.048600	-100%
	Remain Sum Shldr-Peak >1,000 kWh	$0.048600	$0.000000	-$0.048600	-100%
	Remain Sum Off-Peak First 500 kWh	$0.025300	$0.000000	-$0.025300	-100%
	Remain Sum Off-Peak 501-1,000 kWh	$0.025300	$0.000000	-$0.025300	-100%
	Remain Sum Off-Peak >1,000 kWh	$0.025300	$0.000000	-$0.025300	-100%
	Win On-Peak First 500 kWh	$0.065200	$0.061158	-$0.004042	-6%
	Win On-Peak 501-1,000 kWh	$0.065200	$0.083100	$0.017900	27%
	Win On-Peak >1,000 kWh	$0.065200	$0.083100	$0.017900	27%
	Win Off-Peak First 500 kWh	$0.015300	$0.061158	$0.045858	300%
	Win Off-Peak 501-1,000 kWh	$0.015300	$0.083100	$0.067800	443%
	Win Off-Peak >1,000 kWh	$0.015300	$0.083100	$0.067800	443%
	Base Power Mid Summer On-Peak kWh	$0.055698	$0.043911	-$0.011787	-21%
	Base Power Mid Summer Shoulder kWh	$0.048198	$0.000000	-$0.048198	-100%
	Base Power Mid Summer Off-Peak kWh	$0.023198	$0.022738	-$0.000461	-2%
	Base Power Remaining Summer On-Peak kWh	$0.055698	$0.000000	-$0.055698	-100%
	Base Power Remaining Summer Shoulder kWh	$0.048198	$0.000000	-$0.048198	-100%
	Base Power Remaining Summer Off-Peak kWh	$0.023198	$0.000000	-$0.023198	-100%
	Base Power Winter On-Peak kWh	$0.040698	$0.028809	-$0.011889	-29%
	Base Power Winter Off-Peak kWh	$0.020698	$0.023878	$0.003180	15%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
TE8-01	**Residential Service Standard (Frozen Lifeline Medical % Discount)**				
	Basic Service Charge Per Month	$6.90	$17.00	$10.10	146%
	Sum First 500 kWh	$0.061100	$0.061158	$0.000058	0%
	Sum 501-1,000 kWh	$0.061100	$0.083100	$0.022000	36%
	Sum >1,000 kWh	$0.061100	$0.083100	$0.022000	36%
	Win First 500 kWh	$0.057000	$0.061158	$0.004158	7%
	Win 501-1,000 kWh	$0.057000	$0.083100	$0.026100	46%
	Win >1,000 kWh	$0.057000	$0.083100	$0.026100	46%
	Base Power Summer kWh	$0.033198	$0.035868	$0.002670	8%
	Base Power Winter kWh	$0.025698	$0.032537	$0.006839	27%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
TE8-21	**Residential Time of Use (Frozen Lifeline Medical % Discount)**				
	Basic Service Charge Per Month	$8.86	$17.00	$8.14	92%
	Sum On-Peak First 500 kWh	$0.078800	$0.061158	-$0.017642	-22%
	Sum On-Peak 501-1,000 kWh	$0.078800	$0.083100	$0.004300	5%
	Sum On-Peak >1,000 kWh	$0.078800	$0.083100	$0.004300	5%
	Sum Off-Peak First 500 kWh	$0.030100	$0.061158	$0.031058	103%
	Sum Off-Peak 501-1,000 kWh	$0.030100	$0.083100	$0.053000	176%
	Sum Off-Peak >1,000 kWh	$0.030100	$0.083100	$0.053000	176%
	Win On-Peak First 500 kWh	$0.065200	$0.061158	-$0.004042	-6%
	Win On-Peak 501-1,000 kWh	$0.065200	$0.083100	$0.017900	27%
	Win On-Peak >1,000 kWh	$0.065200	$0.083100	$0.017900	27%
	Win Off-Peak First 500 kWh	$0.033000	$0.061158	$0.028158	85%
	Win Off-Peak 501-1,000 kWh	$0.033000	$0.083100	$0.050100	152%
	Win Off-Peak >1,000 kWh	$0.033000	$0.083100	$0.050100	152%
	Base Power Summer On-Peak kWh	$0.053198	$0.051660	-$0.001538	-3%
	Base Power Summer Off-Peak kWh	$0.023198	$0.026750	$0.003552	15%
	Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
	Base Power Winter Off-peak kWh	$0.020698	$0.028092	$0.007394	36%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M

Tucson Electric Power Company
Comparison of Present and Proposed Rates
Test Period Ended June 30, 2015

Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
TE8-70	**Residential Time of Use (Frozen Lifeline Medical % Discount)**				
	Basic Service Charge Per Month	$8.78	$17.00	$8.22	94%
	Sum On-Peak First 500 kWh	$0.139300	$0.061158	-$0.078142	-56%
	Sum On-Peak 501-1,000 kWh	$0.139300	$0.083100	-$0.056200	-40%
	Sum On-Peak >1,000 kWh	$0.139300	$0.083100	-$0.056200	-40%
	Sum Shldr-Peak First 500 kWh	$0.074000	$0.061158	-$0.012842	-17%
	Sum Shldr-Peak 501-1,000 kWh	$0.074000	$0.083100	$0.009100	12%
	Sum Shldr-Peak >1,000 kWh	$0.074000	$0.083100	$0.009100	12%
	Sum Off-Peak First 500 kWh	$0.037900	$0.061158	$0.023258	61%
	Sum Off-Peak 501-1,000 kWh	$0.037900	$0.083100	$0.045200	119%
	Sum Off-Peak >1,000 kWh	$0.037900	$0.083100	$0.045200	119%
	Win On-Peak First 500 kWh	$0.092500	$0.061158	-$0.031342	-34%
	Win On-Peak 501-1,000 kWh	$0.092500	$0.083100	-$0.009400	-10%
	Win On-Peak >1,000 kWh	$0.092500	$0.083100	-$0.009400	-10%
	Win Off-Peak First 500 kWh	$0.024900	$0.061158	$0.036258	146%
	Win Off-Peak 501-1,000 kWh	$0.024900	$0.083100	$0.058200	234%
	Win Off-Peak >1,000 kWh	$0.024900	$0.083100	$0.058200	234%
	Base Power Summer On-Peak kWh	$0.055698	$0.051660	-$0.004038	-7%
	Base Power Summer Shoulder kWh	$0.048198	$0.051660	$0.003462	7%
	Base Power Summer Off-Peak kWh	$0.023198	$0.026750	$0.003552	15%
	Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
	Base Power Winter Off-peak kWh	$0.020698	$0.028092	$0.007394	36%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
TE8-201A	**Special Residential Service (Frozen Lifeline Medical % Discount)**				
	Basic Service Charge Per Month	$6.90	$17.00	$10.10	146%
	Mid Sum First 500 kWh	$0.061100	$0.061158	$0.000058	0%
	Mid Sum 501-1,000 kWh	$0.061100	$0.083100	$0.022000	36%
	Mid Sum >1,000 kWh	$0.061100	$0.083100	$0.022000	36%
	Remain Sum First 500 kWh	$0.043600	$0.000000	-$0.043600	-100%
	Remain Sum 501-1,000 kWh	$0.043600	$0.000000	-$0.043600	-100%
	Remain Sum >1,000 kWh	$0.043600	$0.000000	-$0.043600	-100%
	Win First 500 kWh	$0.041300	$0.061158	$0.019858	48%
	Win 501-1,000 kWh	$0.041300	$0.083100	$0.041800	101%
	Win >1,000 kWh	$0.041300	$0.083100	$0.041800	101%
	Base Power Mid Summer kWh	$0.033198	$0.028694	-$0.004504	-14%
	Base Power Remaining Summer kWh	$0.033198	$0.000000	-$0.033198	-100%
	Base Power Winter kWh	$0.027198	$0.026030	-$0.001168	-4%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
TE6-01BC	**Residential Service Standard (Frozen Lifeline Flat Discount) Bright Community Solar**				
	Basic Service Charge Per Month	$6.90	$17.00	$10.10	146%
	Sum First 500 kWh	$0.061100	$0.061158	$0.000058	0%
	Sum 501-1,000 kWh	$0.061100	$0.083100	$0.022000	36%
	Sum >1,000 kWh	$0.061100	$0.083100	$0.022000	36%
	Win First 500 kWh	$0.057000	$0.061158	$0.004158	7%
	Win 501-1,000 kWh	$0.057000	$0.083100	$0.026100	46%
	Win >1,000 kWh	$0.057000	$0.083100	$0.026100	46%
	Base Power Summer kWh	$0.033198	$0.035868	$0.002670	8%
	Base Power Winter kWh	$0.025698	$0.032537	$0.006839	27%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
TE-R-01LL	**Residential Service Standard**				
	Basic Service Charge Per Month	$10.00	$17.00	$7.00	70%
	Sum First 500 kWh	$0.056200	$0.061158	$0.004958	9%
	Sum 501-1,000 kWh	$0.067200	$0.083100	$0.015900	24%
	Sum 1,001-3,500 kWh	$0.079800	$0.083100	$0.003300	4%
	Sum>3,500 kWh	$0.088200	$0.083100	-$0.005100	-6%
	Win First 500 kWh	$0.056200	$0.061158	$0.004958	9%
	Win 501-1,000 kWh	$0.065200	$0.083100	$0.017900	27%
	Win 1,001-3,500 kWh	$0.078100	$0.083100	$0.005000	6%
	Win>3,500 kWh	$0.087100	$0.083100	-$0.004000	-5%
	Base Power Summer kWh	$0.035111	$0.035868	$0.000757	2%
	Base Power Winter kWh	$0.031532	$0.032537	$0.001005	3%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M

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Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
TE-R01LB	**Residential Service R-01 Bright Community Solar**				
	Basic Service Charge Per Month	$10.00	$17.00	$7.00	70%
	Sum First 500 kWh	$0.056200	$0.061158	$0.004958	9%
	Sum 501-1,000 kWh	$0.067200	$0.083100	$0.015900	24%
	Sum 1,001-3,500 kWh	$0.079800	$0.083100	$0.003300	4%
	Sum>3,500 kWh	$0.088200	$0.083100	-$0.005100	-6%
	Win First 500 kWh	$0.056200	$0.061158	$0.004958	9%
	Win 501-1,000 kWh	$0.065200	$0.083100	$0.017900	27%
	Win 1,001-3,500 kWh	$0.078100	$0.083100	$0.005000	6%
	Win>3,500 kWh	$0.087100	$0.083100	-$0.004000	-5%
	Base Power Summer kWh	$0.035111	$0.035868	$0.000757	2%
	Base Power Winter kWh	$0.031532	$0.032537	$0.001005	3%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
TE-201AL	**Special Residential Electric Service**				
	Basic Service Charge Per Month	$10.00	$17.00	$7.00	70%
	Sum First 500 kWh	$0.050600	$0.061158	$0.010558	21%
	Sum 501-1,000 kWh	$0.060500	$0.083100	$0.022600	37%
	Sum 1,001-3,500 kWh	$0.071800	$0.083100	$0.011300	16%
	Sum>3,500 kWh	$0.079400	$0.083100	$0.003700	5%
	Win First 500 kWh	$0.050600	$0.061158	$0.010558	21%
	Win 501-1,000 kWh	$0.058700	$0.083100	$0.024400	42%
	Win 1,001-3,500 kWh	$0.070300	$0.083100	$0.012800	18%
	Win>3,500 kWh	$0.078400	$0.083100	$0.004700	6%
	Base Power Summer kWh	$0.035111	$0.028694	-$0.006417	-18%
	Base Power Winter kWh	$0.031532	$0.026030	-$0.005502	-17%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
TE-201BL	**Residential Time of Use**				
	Basic Service Charge Per Month	$11.50	$17.00	$5.50	48%
	Sum On-peak First 500 kWh	$0.056800	$0.061158	$0.004358	8%
	Sum On-peak 501-1,000 kWh	$0.056800	$0.083100	$0.026300	46%
	Sum On-peak1,001-3,500 kWh	$0.056800	$0.083100	$0.026300	46%
	Sum On-peak >3,500 kWh	$0.056800	$0.083100	$0.026300	46%
	Sum Off-peak First 500 kWh	$0.044000	$0.061158	$0.017158	39%
	Sum Off-peak 501-1,000 kWh	$0.044000	$0.083100	$0.039100	89%
	Sum Off-peak1,001-3,500 kWh	$0.044000	$0.083100	$0.039100	89%
	Sum Off-peak >3,500 kWh	$0.044000	$0.083100	$0.039100	89%
	Win On-peak First 500 kWh	$0.048300	$0.061158	$0.012858	27%
	Win On-peak 501-1,000 kWh	$0.048300	$0.083100	$0.034800	72%
	Win On-peak1,001-3,500 kWh	$0.048300	$0.083100	$0.034800	72%
	Win On-peak >3,500 kWh	$0.048300	$0.083100	$0.034800	72%
	Win Off-peak First 500 kWh	$0.035500	$0.061158	$0.025658	72%
	Win Off-peak 501-1,000 kWh	$0.035500	$0.083100	$0.047600	134%
	Win Off-peak1,001-3,500 kWh	$0.035500	$0.083100	$0.047600	134%
	Win Off-peak >3,500 kWh	$0.035500	$0.083100	$0.047600	134%
	Base Power Summer On-Peak kWh	$0.050669	$0.041328	-$0.009341	-18%
	Base Power Summer Off-Peak kWh	$0.026679	$0.021400	-$0.005279	-20%
	Base Power Winter On-peak kWh	$0.032893	$0.027114	-$0.005779	-18%
	Base Power Winter Off-peak kWh	$0.027092	$0.022474	-$0.004618	-17%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M

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Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
TE-R8OLL	**Residential Time of Use**				
	Basic Service Charge Per Month	$11.50	$17.00	$5.50	48%
	Sum On-peak First 500 kWh	$0.066800	$0.061158	-$0.005642	-8%
	Sum On-peak 501-1,000 kWh	$0.066800	$0.083100	$0.016300	24%
	Sum On-peak1,001-3,500 kWh	$0.066800	$0.083100	$0.016300	24%
	Sum On-peak >3,500 kWh	$0.066800	$0.083100	$0.016300	24%
	Sum Off-peak First 500 kWh	$0.051800	$0.061158	$0.009358	18%
	Sum Off-peak 501-1,000 kWh	$0.051800	$0.083100	$0.031300	60%
	Sum Off-peak1,001-3,500 kWh	$0.051800	$0.083100	$0.031300	60%
	Sum Off-peak >3,500 kWh	$0.051800	$0.083100	$0.031300	60%
	Win On-peak First 500 kWh	$0.056800	$0.061158	$0.004358	8%
	Win On-peak 501-1,000 kWh	$0.056800	$0.083100	$0.026300	46%
	Win On-peak1,001-3,500 kWh	$0.056800	$0.083100	$0.026300	46%
	Win On-peak >3,500 kWh	$0.056800	$0.083100	$0.026300	46%
	Win Off-peak First 500 kWh	$0.041800	$0.061158	$0.019358	46%
	Win Off-peak 501-1,000 kWh	$0.041800	$0.083100	$0.041300	99%
	Win Off-peak1,001-3,500 kWh	$0.041800	$0.083100	$0.041300	99%
	Win Off-peak >3,500 kWh	$0.041800	$0.083100	$0.041300	99%
	Base Power Summer On-Peak kWh	$0.050669	$0.051660	$0.000991	2%
	Base Power Summer Off-Peak kWh	$0.026679	$0.026750	$0.000071	0%
	Base Power Winter On-peak kWh	$0.032893	$0.033893	$0.001000	3%
	Base Power Winter Off-peak kWh	$0.027092	$0.028092	$0.001000	4%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
TE-R8LL	**Residential Time of Use Super Peak Lifeline**				
	Basic Service Charge Per Month	$11.50	$17.00	$5.50	48%
	Sum On-peak First 500 kWh	$0.097100	$0.061158	-$0.035942	-37%
	Sum On-peak 501-1,000 kWh	$0.097100	$0.083100	-$0.014000	-14%
	Sum On-peak1,001-3,500 kWh	$0.120100	$0.083100	-$0.037000	-31%
	Sum On-peak >3,500 kWh	$0.120100	$0.083100	-$0.037000	-31%
	Sum Off-peak First 500 kWh	$0.048500	$0.061158	$0.012658	26%
	Sum Off-peak 501-1,000 kWh	$0.048500	$0.083100	$0.034600	71%
	Sum Off-peak1,001-3,500 kWh	$0.071500	$0.083100	$0.011600	16%
	Sum Off-peak >3,500 kWh	$0.071500	$0.083100	$0.011600	16%
	Win On-peak First 500 kWh	$0.089100	$0.061158	-$0.027942	-31%
	Win On-peak 501-1,000 kWh	$0.089100	$0.083100	-$0.006000	-7%
	Win On-peak1,001-3,500 kWh	$0.112100	$0.083100	-$0.029000	-26%
	Win On-peak >3,500 kWh	$0.112100	$0.083100	-$0.029000	-26%
	Win Off-peak First 500 kWh	$0.038500	$0.061158	$0.022658	59%
	Win Off-peak 501-1,000 kWh	$0.038500	$0.083100	$0.044600	116%
	Win Off-peak1,001-3,500 kWh	$0.061500	$0.083100	$0.021600	35%
	Win Off-peak >3,500 kWh	$0.061500	$0.083100	$0.021600	35%
	Base Power Summer On-Peak kWh	$0.080100	$0.081060	$0.000960	1%
	Base Power Summer Off-Peak kWh	$0.022200	$0.022750	$0.000550	2%
	Base Power Winter On-peak kWh	$0.040200	$0.041293	$0.001093	3%
	Base Power Winter Off-peak kWh	$0.020500	$0.021492	$0.000992	5%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
TE-PESXX	**Prepay Electric Service**				
	Basic Service Charge Per Day	N/M	$0.74	N/M	N/M
	Sum First 20 kWh Per Day	N/M	$0.065000	N/M	N/M
	Sum >20 kWh Per Day	N/M	$0.084000	N/M	N/M
	Win First 20 kWh Per Day	N/M	$0.065000	N/M	N/M
	Win >20 kWh Per Day	N/M	$0.084000	N/M	N/M
	Base Power Summer kWh	N/M	$0.035868	N/M	N/M
	Base Power Winter kWh	N/M	$0.032537	N/M	N/M
	PPFAC Charge	N/M	$0.000000	N/M	N/M
TE-GS10	**Small General Service**				
	Basic Service Charge Single Phase Per Mo.	$15.50	$27.00	$11.50	74%
	Basic Service Charge Three Phase Per Mo.	$20.50	$32.00	$11.50	56%
	Sum First 500 kWh	$0.077000	$0.081850	$0.004850	6%
	Sum >500 kWh	$0.097800	$0.101850	$0.004050	4%
	Win First 500 kWh	$0.057000	$0.071900	$0.014900	26%
	Win >500 kWh	$0.079000	$0.092900	$0.013900	18%
	Base Power Summer kWh	$0.035111	$0.035868	$0.000757	2%
	Base Power Winter kWh	$0.031532	$0.032537	$0.001005	3%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M

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Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
TE-GSXX	**Small General Service Demand**				
	Basic Service Charge Per Month	N/M	$27.00	N/M	N/M
	Demand 0-7 kW	N/M	$9.60	N/M	N/M
	Demand > 7 kW	N/M	$13.75	N/M	N/M
	Sum kWh	N/M	$0.057770	N/M	N/M
	Win kWh	N/M	$0.047770	N/M	N/M
	Base Power Summer kWh	N/M	$0.035868	N/M	N/M
	Base Power Winter kWh	N/M	$0.032537	N/M	N/M
	PPFAC Charge	N/M	$0.000000	N/M	N/M
TE-GS11	**Mobile Home Park Service (FROZEN)**				
	Basic Service Charge Single Phase Per Mo.	$15.50	$27.00	$11.50	74%
	Basic Service Charge Three Phase Per Mo.	$20.50	$32.00	$11.50	56%
	Sum kWh	$0.082000	$0.085200	$0.003200	4%
	Win kWh	$0.062000	$0.085200	$0.023200	37%
	Base Power Summer kWh	$0.035111	$0.035868	$0.000757	2%
	Base Power Winter kWh	$0.031532	$0.032537	$0.001005	3%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
TE-GS76	**Small General Service Time of Use**				
	Basic Service Charge	$17.50	$27.00	$9.50	54%
	Sum On-peak First 500 kWh	$0.099100	$0.081850	-$0.017250	-17%
	Sum On-peak >500 kWh	$0.099100	$0.101850	$0.002750	3%
	Sum Off-peak First 500 kWh	$0.084900	$0.081850	-$0.003050	-4%
	Sum Off-peak >500 kWh	$0.084900	$0.101850	$0.016950	20%
	Winter On-peak First 500 kWh	$0.081400	$0.071900	-$0.009500	-12%
	Winter On-peak >500 kWh	$0.081400	$0.092900	$0.011500	14%
	Winter Off-Peak First 500 kWh	$0.064900	$0.071900	$0.007000	11%
	Winter Off-Peak >500 kWh	$0.064900	$0.092900	$0.028000	43%
	Base Power Summer On-Peak kWh	$0.050669	$0.051660	$0.000991	2%
	Base Power Summer Off-Peak kWh	$0.026679	$0.026750	$0.000071	0%
	Base Power Winter On-peak kWh	$0.032893	$0.033893	$0.001000	3%
	Base Power Winter Off-peak kWh	$0.027092	$0.028092	$0.001000	4%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
	Solar Block Rate for Small General Service Rate GS-10	$0.053274	$0.054197	$0.000923	2%
TE-GSXXX	**Small General Service Demand Time of Use**				
	Basic Service Charge Per Month	N/M	$27.00	N/M	N/M
	Demand 0-7 kW	N/M	$9.60	N/M	N/M
	Demand > 7 kW	N/M	$13.75	N/M	N/M
	Sum On-peak kWh	N/M	$0.057770	N/M	N/M
	Sum Off-peak kWh	N/M	$0.057770	N/M	N/M
	Win On-peak kWh	N/M	$0.047770	N/M	N/M
	Win Off-peak kWh	N/M	$0.047770	N/M	N/M
	Base Power Summer On-Peak kWh	N/M	$0.051660	N/M	N/M
	Base Power Summer Off-Peak kWh	N/M	$0.026750	N/M	N/M
	Base Power Winter On-peak kWh	N/M	$0.033893	N/M	N/M
	Base Power Winter Off-peak kWh	N/M	$0.028092	N/M	N/M
	PPFAC Charge	N/M	$0.000000	N/M	N/M
TE-G10BC	**General Service Bright Community Solar**				
	Basic Service Charge Single Phase Per Month	$15.50	$27.00	$11.50	74%
	Basic Service Charge Three Phase Per Month	$20.50	$32.00	$11.50	56%
	Sum First 500 kWh	$0.077000	$0.081850	$0.004850	6%
	Sum>500 kWh	$0.097800	$0.101850	$0.004050	4%
	Winter First 500 kWh 0568	$0.057000	$0.071900	$0.014900	26%
	Winter >500 kWh 0788	$0.079000	$0.092900	$0.013900	18%
	Winter First 500 kWh 0570	$0.057000	$0.000000	-$0.057000	-100%
	Winter >500 kWh 0790	$0.079000	$0.000000	-$0.079000	-100%
	Base Power Summer kWh	$0.035111	$0.035868	$0.000757	2%
	Base Power Winter kWh	$0.031532	$0.032537	$0.001005	3%
	Solar Blocks kWh_2011	$0.028475	$0.028475	$0.000000	0%
	Solar Blocks kWh_2013	$0.033274	$0.033274	$0.000000	0%
	Solar Blocks kWh_20xx	$0.028475	$0.028475	$0.000000	0%
	Credited Solar Blocks kWh_2011	-$0.028475	-$0.028475	$0.000000	0%
	Credited Solar Blocks kWh_2013	-$0.033274	-$0.033274	$0.000000	0%
	Credited Solar Blocks kWh_20xx	-$0.028475	-$0.028475	$0.000000	0%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M

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Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
TE-GSM10	**Small General Service (Municipal Transitional Adjustment)**				
	Basic Service Charge Single Phase Per Month	$15.50	$27.00	$11.50	74%
	Basic Service Charge Three Phase Per Month	$20.50	$32.00	$11.50	56%
	Sum First 500 kWh	$0.077000	$0.081850	$0.004850	6%
	Sum>500 kWh	$0.097800	$0.101850	$0.004050	4%
	Win First 500 kWh	$0.057000	$0.071900	$0.014900	26%
	Win>500 kWh	$0.079000	$0.092900	$0.013900	18%
	Transitional Adjustment	16.50%	0.00%	-$0.165000	-100%
	Base Power Summer kWh	$0.035111	$0.035868	$0.000757	2%
	Base Power Winter kWh	$0.031532	$0.032537	$0.001005	3%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
TE-G10MBC	**General Service (Municipal Transitional Adjustment) Bright Community Solar**				
	Basic Service Charge Three Phase Per Month	$20.50	$27.00	$6.50	32%
	Sum First 500 kWh	$0.077000	$0.081850	$0.004850	6%
	Sum>500 kWh	$0.097800	$0.101850	$0.004050	4%
	Win First 500 kWh	$0.057000	$0.071900	$0.014900	26%
	Win>500 kWh	$0.079000	$0.092900	$0.013900	18%
	Transitional Adjustment	16.50%	0.00%	-$0.165000	-100%
	Base Power Summer kWh	$0.035111	$0.035868	$0.000757	2%
	Base Power Winter kWh	$0.031532	$0.032537	$0.001005	3%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
	RT 43 Water Pumping				
TE-GS36	GS-36 (43) Water Pumping-Firm Service				
	Basic Service Charge Per Mo.	$15.50	$27.00	$11.50	74%
	Sum kWh	$0.068000	$0.085500	$0.017500	26%
	Win kWh	$0.048000	$0.065500	$0.017500	36%
	Base Power Summer kWh	$0.035111	$0.035868	$0.000757	2%
	Base Power Winter kWh	$0.031532	$0.032537	$0.001005	3%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
TE-GS37	GS-37 Com Water Pumping-Firm w/ Primary Voltage Discount				
	Basic Service Charge Per Mo.	$15.50	$27.00	$11.50	74%
	Sum kWh	$0.064600	$0.081225	$0.016625	26%
	Win kWh	$0.045600	$0.062225	$0.016625	36%
	Base Power Summer kWh	$0.033355	$0.034075	$0.000719	2%
	Base Power Winter kWh	$0.029955	$0.030910	$0.000955	3%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
TE-GS38	GS-38 (43) Water Pumping-Interruptible Serv				
	Basic Service Charge Per Mo.	$15.50	$27.00	$11.50	74%
	Sum kWh	$0.042000	$0.059500	$0.017500	42%
	Win kWh	$0.027000	$0.044500	$0.017500	65%
	Base Power Summer kWh	$0.031310	$0.032100	$0.000790	3%
	Base Power Winter kWh	$0.028420	$0.029400	$0.000980	3%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
TE-GS39	GS-39 (43) Water Pumping-Interupt w/Primary Voltage Discount				
	Basic Service Charge Per Mo.	$15.50	$27.00	$11.50	74%
	Sum kWh	$0.039900	$0.056500	$0.016600	42%
	Win kWh	$0.025650	$0.042300	$0.016650	65%
	Base Power Summer kWh	$0.029745	$0.030495	$0.000750	3%
	Base Power Winter kWh	$0.026999	$0.027930	$0.000931	3%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
TE-MGS	**Medium General Service**				
	Basic Service Charge Per Month	N/M	$40.00	N/M	N/M
	Summer Demand Charge Per kW	N/M	$7.00	N/M	N/M
	Winter Demand Charge Per kW	N/M	$5.00	N/M	N/M
	Summer kWh	N/M	$0.084500	N/M	N/M
	Winter kWh	N/M	$0.073500	N/M	N/M
	Base Power Summer kWh	N/M	$0.035868	N/M	N/M
	Base Power Winter kWh	N/M	$0.032537	N/M	N/M
	PPFAC Charge	N/M	$0.000000	N/M	N/M
	Solar Block Rate for Medium General Service Rate MGS	$0.053227	0.05418		

Tucson Electric Power Company
Comparison of Present and Proposed Rates
Test Period Ended June 30, 2015

Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
TE-MGSTOU	**Medium General Service TOU**				
	Basic Service Charge Per Month	N/M	$40.00	N/M	N/M
	Demand Summer On-Peak per kW	N/M	$8.00	N/M	N/M
	Demand Summer Off-Peak Excess Per kW	N/M	$4.76	N/M	N/M
	Demand Winter On-Peak Per kW	N/M	$4.00	N/M	N/M
	Demand Winter Off-Peak Excess Per kW	N/M	$3.50	N/M	N/M
	Summer On-Peak kWh	N/M	$0.115800	N/M	N/M
	Summer Off-Peak kWh	N/M	$0.073100	N/M	N/M
	Winter On-Peak kWh	N/M	$0.115800	N/M	N/M
	Winter Off-Peak kWh	N/M	$0.073100	N/M	N/M
	Base Power Summer On-Peak kWh	N/M	$0.051660	N/M	N/M
	Base Power Summer Off-Peak kWh	N/M	$0.026750	N/M	N/M
	Base Power Winter On-peak kWh	N/M	$0.033893	N/M	N/M
	Base Power Winter Off-peak kWh	N/M	$0.028092	N/M	N/M
	PPFAC Charge	N/M	$0.000000	N/M	N/M
TE-MGSBC	**Medium General Service Bright Community solar**				
	Basic Service Charge Per Month	N/M	$40.00	N/M	N/M
	Summer Demand Charge Per kW	N/M	$7.00	N/M	N/M
	Winter Demand Charge Per kW	N/M	$5.00	N/M	N/M
	Summer kWh	N/M	$0.084500	N/M	N/M
	Winter kWh	N/M	$0.073500	N/M	N/M
	Base Power Summer kWh	N/M	$0.035868	N/M	N/M
	Base Power Winter kWh	N/M	$0.032537	N/M	N/M
	PPFAC Charge	N/M	$0.000000	N/M	N/M
TE-LGS13	**Large General Service**				
	Basic Service Charge Per Month	$775.00	$950.00	$175.00	23%
	Demand Charge Per kW	$15.25	$17.55	$2.30	15%
	Summer kWh	$0.0192	$0.0228	$0.003600	19%
	Winter kWh	$0.0134	$0.0173	$0.003900	29%
	Base Power Summer kWh	$0.035111	$0.035868	$0.000757	2%
	Base Power Winter kWh	$0.031532	$0.032537	$0.001005	3%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
TE-LG85	**Large General Service TOU**				
	Basic Service Charge Per Month	$950.00	$950.00	$0.00	0%
	Demand Summer On-Peak per kW	$14.55	$22.15	$7.60	52%
	Demand Summer Off-Peak Per kW	$10.92	$10.92	$0.00	0%
	Demand Winter On-Peak Per kW	$11.59	$18.50	$6.91	60%
	Demand Winter Off-Peak Per kW	$9.10	$9.10	$0.00	0%
	Summer On-Peak kWh	$0.008600	$0.018540	$0.009940	116%
	Summer Off-Peak kWh	$0.006000	$0.012700	$0.006700	112%
	Winter On-Peak kWh	$0.003000	$0.007100	$0.004100	137%
	Winter Off-Peak kWh	$0.000500	$0.001250	$0.000750	150%
	Base Power Summer On-Peak kWh	$0.050669	$0.051660	$0.000991	2%
	Base Power Summer Off-Peak kWh	$0.026679	$0.026750	$0.000071	0%
	Base Power Winter On-peak kWh	$0.032893	$0.033893	$0.001000	3%
	Base Power Winter Off-peak kWh	$0.027092	$0.028092	$0.001000	4%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
TE-L13BC	**Large General Service Brigh Community Solar**				
	Basic Service Charge Per Month	$775.00	$950.00	$175.00	23%
	Demand Charge Per kW	$15.25	$17.55	$2.30	15%
	Summer kWh	$0.0192	$0.0228	$0.003600	19%
	Winter kWh	$0.0134	$0.0173	$0.003900	29%
	Base Power Summer kWh	$0.035111	$0.035868	$0.000757	2%
	Base Power Winter kWh	$0.031532	$0.032537	$0.001005	3%
	Solar_Blocks_kWh_053227_2P	$0.033227	$0.033227	$0.000000	0%
	Solar_Blocks_kWh_039371_1_1P	$0.029371	$0.029371	$0.000000	0%
	Credited_Blocks_kWh_039371_1_1P	-$0.029371	-$0.029371	$0.000000	0%
	Solar_Blocks_kWh_039371_2_1P	$0.029371	$0.029371	$0.000000	0%
	Credited_Blocks_kWh_039371_2_1P	-$0.029371	-$0.029371	$0.000000	0%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M

Tucson Electric Power Company
Comparison of Present and Proposed Rates
Test Period Ended June 30, 2015

Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
TE-LLP14	**Large Light & Power**		TARIFF CLOSED	TARIFF CLOSED	
	Basic Service Charge	$1,800.00	N/M	N/M	N/M
	Demand Charge	21.98	N/M	N/M	N/M
	Summer kWh	0.0032	N/M	N/M	N/M
	Winter kWh	0.0021	N/M	N/M	N/M
	Base Power Summer kWh	0.031611	N/M	N/M	N/M
	Base Power Winter kWh	0.028388	N/M	N/M	N/M
	PPFAC Charge	$0.006820	N/M	N/M	N/M
TE-LLP90	Large Power Service Time of Use				
	Basic Service Charge Per Month	$2,000.00	$10,000.00	$8,000.00	400%
	Demand Summer On-Peak per kW	$20.49	$21.00	$0.51	2%
	Demand Summer Off-Peak Excess Per kW	$12.49	$12.49	$0.00	0%
	Demand Winter On-Peak Per kW	$15.49	$16.55	$1.06	7%
	Demand Winter Off-Peak Excess Per kW	$9.99	$9.10	-$0.89	-9%
	Summer On-Peak kWh	$0.006900	$0.007800	$0.000900	13%
	Summer Off-Peak kWh	$0.006500	$0.007800	$0.001300	20%
	Winter On-Peak kWh	$0.007500	$0.007800	$0.000300	4%
	Winter Off-Peak kWh	$0.007100	$0.007800	$0.000700	10%
	Base Power Summer On-Peak kWh	$0.045568	$0.049077	$0.003509	8%
	Base Power Summer Off-Peak kWh	$0.023985	$0.025413	$0.001428	6%
	Base Power Winter On-peak kWh	$0.029581	$0.032198	$0.002617	9%
	Base Power Winter Off-peak kWh	$0.024352	$0.026687	$0.002335	10%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
TE-138	Transmission Service Rate 138kV				
	Basic Service Charge Per Month	N/M	$15,000.00	N/M	N/M
	Demand Summer On-Peak per kW	N/M	$17.15	N/M	N/M
	Demand Summer Off-Peak Excess Per kW	N/M	$12.49	N/M	N/M
	Demand Winter On-Peak Per kW	N/M	$14.15	N/M	N/M
	Demand Winter Off-Peak Excess Per kW	N/M	$9.10	N/M	N/M
	Summer On-Peak kWh	N/M	$0.007800	N/M	N/M
	Summer Off-Peak kWh	N/M	$0.007800	N/M	N/M
	Winter On-Peak kWh	N/M	$0.007800	N/M	N/M
	Winter Off-Peak kWh	N/M	$0.007800	N/M	N/M
	Base Power Summer On-Peak kWh	N/M	$0.048044	N/M	N/M
	Base Power Summer Off-Peak kWh	N/M	$0.024878	N/M	N/M
	Base Power Winter On-peak kWh	N/M	$0.031520	N/M	N/M
	Base Power Winter Off-peak kWh	N/M	$0.026126	N/M	N/M
	PPFAC Charge	N/M	$0.000000	N/M	N/M
TE-P41&P47	P41 Traffic Signal & Street Lighting				
	Basic Service Charge Per Month	$0.00	$0.00	$0.00	0%
	All Delivery kWh	$0.047600	$0.065100	$0.017500	37%
	Base Power Summer kWh	$0.035111	$0.035868	$0.000757	2%
	Base Power Winter kWh	$0.031532	$0.032537	$0.001005	3%
	PPFAC Charge	$0.006820	$0.000000	N/M	N/M
TE-P50	Lighting Service				
TE-R51 + TE-R5:	100OH	$8.19	$11.95	$3.76	46%
TE-C52 & 52A	100UG	$23.72	$34.60	$10.88	46%
	250OH	$12.29	$17.92	$5.63	46%
	250UG	$27.82	$40.58	$12.76	46%
	400OH	$18.70	$27.29	$8.59	46%
	400UG	$34.23	$49.92	$15.69	46%
	55OH	$8.19	$11.95	$3.76	46%
	55P	$8.19	$11.95	$3.76	46%
	55UG	$23.72	$34.60	$10.88	46%
	70UG	$23.72	$34.60	$10.88	46%
	Pole	$2.86	$4.17	$1.31	46%
	Base Power				
	100OH	$1.34	$1.37	$0.03	2%
	100UG	$1.34	$1.37	$0.03	2%
	250OH	$3.36	$3.42	$0.06	2%
	250UG	$3.36	$3.42	$0.06	2%
	400OH	$5.38	$5.30	-$0.08	-1%
	400UG	$5.38	$5.30	-$0.08	-1%
	55OH	$0.85	$0.87	$0.02	2%
	55P	$0.85	$0.87	$0.02	2%
	55UG	$0.85	$0.87	$0.02	2%
	70UG	$0.94	$0.96	$0.02	2%

RESIDENTIAL SERVICE RATE R-01

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill
		500	1000	3500	>3500		500	1000	3500	>3500			
						$10.00	$0.05620	$0.06520	$0.07810	$0.08710	$0.031532	$0.00682	
Small	520	500	20	0	0	$10.00	$28.10	$1.30	$0.00	$0.00	$16.40	$3.55	$59.35
Medium	840	500	340	0	0	$10.00	$28.10	$22.17	$0.00	$0.00	$26.49	$5.73	$92.49
Large	1,250	500	500	250	0	$10.00	$28.10	$32.60	$19.53	$0.00	$39.42	$8.53	$138.18
XLg	1,564	500	500	564	0	$10.00	$28.10	$32.60	$44.05	$0.00	$49.32	$10.67	$174.74
AnnAvg	785	500	285	0	0	$10.00	$28.10	$18.58	$0.00	$0.00	$24.75	$5.35	$86.78
ResAvg	785	500	285	0	0	$10.00	$28.10	$18.58	$0.00	$0.00	$24.75	$5.35	$86.78

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill		
		500	1000	>1000			500	1000	>1000						
						$17.00	$0.06116	$0.08310	$0.08310		$0.032537	$0.00000		$ Change	% Change
Small	520	500	20	0		$17.00	$30.58	$1.66	$0.00		$16.92	$0.00	$66.16	$6.81	11.5%
Medium	840	500	340	0		$17.00	$30.58	$28.25	$0.00		$27.33	$0.00	$103.16	$10.67	11.5%
Large	1,250	500	500	250		$17.00	$30.58	$41.55	$20.78		$40.67	$0.00	$150.58	$12.40	9.0%
XLg	1,564	500	500	564		$17.00	$30.58	$41.55	$46.87		$50.89	$0.00	$186.89	$12.15	7.0%
AnnAvg	785	500	285	0		$17.00	$30.58	$23.68	$0.00		$25.54	$0.00	$96.80	$10.02	11.5%
ResAvg	785	500	285	0		$17.00	$30.58	$23.68	$0.00		$25.54	$0.00	$96.80	$10.02	11.5%

RESIDENTIAL SERVICE RATE R-01

Summer

	BILL IMPACTS CURRENT RATES												
	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill
		500	1000	3500	>3500		500	1000	3500	>3500			
						$10.00	$0.05620	$0.06720	$0.07980	$0.08820	$0.035111	$0.00682	
Small	822	500	322	0	0	$10.00	$28.10	$21.64	$0.00	$0.00	$28.86	$5.61	$94.21
Medium	1,384	500	500	384	0	$10.00	$28.10	$33.60	$30.64	$0.00	$48.59	$9.44	$160.37
Large	1,997	500	500	997	0	$10.00	$28.10	$33.60	$79.56	$0.00	$70.12	$13.62	$235.00
XLg	2,430	500	500	1,430	0	$10.00	$28.10	$33.60	$114.11	$0.00	$85.32	$16.57	$287.70
AnnAvg	785	500	285	0	0	$10.00	$28.10	$19.15	$0.00	$0.00	$27.56	$5.35	$90.16
ResAvg	1,150	500	500	150	0	$10.00	$28.10	$33.60	$11.97	$0.00	$40.38	$7.84	$131.89

	BILL IMPACTS PROPOSED RATES														
	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill		
		500	1000	>1000			500	1000	>1000						
						$17.00	$0.06116	$0.08310	$0.08310		$0.035868	$0.00000			
														$ Change	% Change
Small	822	500	322	0		$17.00	$30.58	$26.76	$0.00		$29.48	$0.00	$103.82	$9.61	10.2%
Medium	1,384	500	500	384		$17.00	$30.58	$41.55	$31.91		$49.64	$0.00	$170.68	$10.31	6.4%
Large	1,997	500	500	997		$17.00	$30.58	$41.55	$82.85		$71.63	$0.00	$243.61	$8.61	3.7%
XLg	2,430	500	500	1,430		$17.00	$30.58	$41.55	$118.83		$87.16	$0.00	$295.12	$7.42	2.6%
AnnAvg	785	500	285	0		$17.00	$30.58	$23.68	$0.00		$28.16	$0.00	$99.42	$9.26	10.3%
ResAvg	1,150	500	500	150		$17.00	$30.58	$41.55	$12.47		$41.25	$0.00	$142.85	$10.96	8.3%

RESIDENTIAL SERVICE DEMAND

WINTER

BILL IMPACTS CURRENT R-01 RATES

	Load Factor	kWh	Delivery (kWh) TIERS				kW	Delivery (kW)		Basic Service Charge	Delivery (Energy)				Delivery (Demand)		Base Fuel	PPFAC	Net Bill
			500	1000	3500	>3500					500	1000	3500	>3500					
										10.00	$0.05620	$0.06520	$0.07810	$0.08710			$0.031532	$0.00682	
Small	0.19	520	500	20	0	0	3.7			10.00	$28.10	$1.30	$0.00	$0.00			$16.40	$3.55	$59.35
Medium	0.23	840	500	340	0	0	5.1			10.00	$28.10	$22.17	$0.00	$0.00			$26.49	$5.73	$92.49
Large	0.26	1,250	500	500	250	0	6.6			10.00	$28.10	$32.60	$19.53	$0.00			$39.42	$8.53	$138.18
XLg	0.28	1,564	500	500	564	0	7.6			10.00	$28.10	$32.60	$44.05	$0.00			$49.32	$10.67	$174.74
AnnAvg	0.22	785	500	285	0	0	4.9			10.00	$28.10	$18.58	$0.00	$0.00			$24.75	$5.35	$86.78
ResAvg	0.22	785	500	285	0	0	4.9			10.00	$28.10	$18.58	$0.00	$0.00			$24.75	$5.35	$86.78

BILL IMPACTS PROPOSED RATES

	Load Factor	kWh	Delivery (kWh) TIERS				kW	Delivery (kW) TIERS		Basic Service Charge	Delivery (Energy)				Delivery (Demand)		Base Fuel	PPFAC	Net Bill		
			500	1000	>1000			7.0	> 7.0		500	1000	>1000		7.0	> 7.0					
										$17.00	$0.02492	$0.02492	$0.02492		$7.40	$11.90	$0.032537	$0.00000			
																				$ Change	% Change
Small	0.19	520	500	20	0		3.7	3.7	0.0	$17.00	$12.46	$0.50	$0.00		$27.38	$0.00	$16.92	$0.00	$74.26	$14.91	25.1%
Medium	0.23	840	500	340	0		5.1	5.1	0.0	$17.00	$12.46	$8.47	$0.00		$37.52	$0.00	$27.33	$0.00	$102.78	$10.29	11.1%
Large	0.26	1,250	500	500	250		6.6	6.6	0.0	$17.00	$12.46	$12.46	$6.23		$48.62	$0.00	$40.67	$0.00	$137.44	-$0.74	-0.5%
XLg	0.28	1,564	500	500	564		7.6	7.0	0.6	$17.00	$12.46	$12.46	$14.05		$51.80	$7.26	$50.89	$0.00	$165.92	-$8.82	-5.0%
AnnAvg	0.22	785	500	285	0		4.9	4.9	0.0	$17.00	$12.46	$7.10	$0.00		$35.89	$0.00	$25.54	$0.00	$97.99	$11.21	12.9%
ResAvg	0.22	785	500	285	0		4.9	4.9	0.0	$17.00	$12.46	$7.10	$0.00		$35.89	$0.00	$25.54	$0.00	$97.99	$11.21	12.9%

RESIDENTIAL SERVICE DEMAND

SUMMER

BILL IMPACTS CURRENT R-01 RATES

	Load Factor	kWh	Delivery (kWh) TIERS				kW	Delivery (kW)		Basic Service Charge	Delivery (Energy)				Delivery (Demand)		Base Fuel	PPFAC	Net Bill
			500	1000	3500	>3500					500	1000	3500	>3500					
										10.00	$0.05620	$0.06720	$0.07980	$0.08820			$0.035111	$0.00682	
Small	0.23	822	500	322	0	0	5.0			10.00	$28.10	$21.64	$0.00	$0.00			$28.86	$5.61	$94.21
Medium	0.27	1,384	500	500	384	0	7.0			10.00	$28.10	$33.60	$30.64	$0.00			$48.59	$9.44	$160.37
Large	0.31	1,997	500	500	997	0	8.9			10.00	$28.10	$33.60	$79.56	$0.00			$70.12	$13.62	$235.00
XLg	0.33	2,430	500	500	1,430	0	10.2			10.00	$28.10	$33.60	$114.11	$0.00			$85.32	$16.57	$287.70
AnnAvg	0.22	785	500	285	0	0	4.9			10.00	$28.10	$19.15	$0.00	$0.00			$27.56	$5.35	$90.16
ResAvg	0.25	1,150	500	500	150	0	6.2			10.00	$28.10	$33.60	$11.97	$0.00			$40.38	$7.84	$131.89

BILL IMPACTS PROPOSED RATES

	Load Factor	kWh	Delivery (kWh) TIERS				kW	Delivery (kW) TIERS		Basic Service Charge	Delivery (Energy)				Delivery (Demand)		Base Fuel	PPFAC	Net Bill		
			500	1000	>1000			7.0	> 7.0		500	1000	>1000		7.0	> 7.0					
										$17.00	$0.02492	$0.02492	$0.02492		$7.40	$11.90	$0.035868	$0.00000			
																				$ Change	% Change
Small	0.23	822	500	322	0		5.0	5.0	0.0	$17.00	$12.46	$8.02	$0.00		$36.93	$0.00	$29.48	$0.00	$103.89	$9.68	10.3%
Medium	0.27	1,384	500	500	384		7.0	7.0	0.0	$17.00	$12.46	$12.46	$9.57		$51.80	$0.36	$49.64	$0.00	$153.29	-$7.08	-4.4%
Large	0.31	1,997	500	500	997		8.9	7.0	1.9	$17.00	$12.46	$12.46	$24.85		$51.80	$23.09	$71.63	$0.00	$213.29	-$21.71	-9.2%
XLg	0.33	2,430	500	500	1,430		10.2	7.0	3.2	$17.00	$12.46	$12.46	$35.64		$51.80	$37.60	$87.16	$0.00	$254.12	-$33.58	-11.7%
AnnAvg	0.22	785	500	285	0		4.9	4.9	0.0	$17.00	$12.46	$7.10	$0.00		$35.89	$0.00	$28.16	$0.00	$100.61	$10.45	11.6%
ResAvg	0.25	1,150	500	500	150		6.2	6.2	0.0	$17.00	$12.46	$12.46	$3.74		$46.03	$0.00	$41.25	$0.00	$132.94	$1.05	0.8%

LIFELINE RESIDENTIAL SERVICE RATE R-01LL

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	3500	>3500		500	1000	3500	>3500					
						$10.00	$0.05620	$0.06520	$0.07810	$0.08710	$0.031532	$0.00682			
Small	473	473	0	0	0	$10.00	$26.58	$0.00	$0.00	$0.00	$14.91	$3.23	$54.72	$45.72	-16.4%
Medium	740	500	240	0	0	$10.00	$28.10	$15.65	$0.00	$0.00	$23.33	$5.05	$82.13	$73.13	-11.0%
Large	1,071	500	500	71	0	$10.00	$28.10	$32.60	$5.55	$0.00	$33.77	$7.30	$117.32	$108.32	-7.7%
XLg	1,310	500	500	310	0	$10.00	$28.10	$32.60	$24.21	$0.00	$41.31	$8.93	$145.15	$136.15	-6.2%
AnnAvg	662	500	162	0	0	$10.00	$28.10	$10.55	$0.00	$0.00	$20.87	$4.51	$74.03	$65.03	-12.2%
ResAvg	785	500	285	0	0	$10.00	$28.10	$18.58	$0.00	$0.00	$24.75	$5.35	$86.78	$77.78	-10.4%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000			500	1000	>1000							
						$17.00	$0.06116	$0.08310	$0.08310		$0.032537	$0.00000				
Small	473	473	0	0		$17.00	$28.93	$0.00	$0.00		$15.39	$0.00	$61.32	$46.32	$0.60	1.3%
Medium	740	500	240	0		$17.00	$30.58	$19.94	$0.00		$24.08	$0.00	$91.60	$76.60	$3.47	4.7%
Large	1,071	500	500	71		$17.00	$30.58	$41.55	$5.90		$34.85	$0.00	$129.88	$114.88	$6.56	6.1%
XLg	1,310	500	500	310		$17.00	$30.58	$41.55	$25.76		$42.62	$0.00	$157.51	$142.51	$6.36	4.7%
AnnAvg	662	500	162	0		$17.00	$30.58	$13.45	$0.00		$21.54	$0.00	$82.57	$67.57	$2.54	3.9%
ResAvg	785	500	285	0		$17.00	$30.58	$23.68	$0.00		$25.54	$0.00	$96.80	$81.80	$4.02	5.2%

LIFELINE RESIDENTIAL SERVICE RATE R-01LL

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	3500	>3500		500	1000	3500	>3500					
						$10.00	$0.05620	$0.06720	$0.07980	$0.08820	$0.035111	$0.00682			
Small	683	500	183	0	0	$10.00	$28.10	$12.30	$0.00	$0.00	$23.98	$4.66	$79.04	$70.04	-11.4%
Medium	1,075	500	500	75	0	$10.00	$28.10	$33.60	$5.99	$0.00	$37.74	$7.33	$122.76	$113.76	-7.3%
Large	1,569	500	500	569	0	$10.00	$28.10	$33.60	$45.41	$0.00	$55.09	$10.70	$182.90	$173.90	-4.9%
XLg	1,880	500	500	880	0	$10.00	$28.10	$33.60	$70.22	$0.00	$66.01	$12.82	$220.75	$211.75	-4.1%
AnnAvg	662	500	162	0	0	$10.00	$28.10	$10.88	$0.00	$0.00	$23.24	$4.51	$76.73	$67.73	-11.7%
ResAvg	1,150	500	500	150	0	$10.00	$28.10	$33.60	$11.97	$0.00	$40.38	$7.84	$131.89	$122.89	-6.8%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$17.00	$0.06116	$0.08310	$0.08310	$0.035868	$0.00000				
Small	683	500	183	0	$17.00	$30.58	$15.21	$0.00	$24.50	$0.00	$87.29	$72.29	$2.25	3.2%
Medium	1,075	500	500	75	$17.00	$30.58	$41.55	$6.23	$38.56	$0.00	$133.92	$118.92	$5.16	4.5%
Large	1,569	500	500	569	$17.00	$30.58	$41.55	$47.28	$56.28	$0.00	$192.69	$177.69	$3.79	2.2%
XLg	1,880	500	500	880	$17.00	$30.58	$41.55	$73.13	$67.43	$0.00	$229.69	$214.69	$2.94	1.4%
AnnAvg	662	500	162	0	$17.00	$30.58	$13.45	$0.00	$23.74	$0.00	$84.77	$69.77	$2.04	3.0%
ResAvg	1,150	500	500	150	$17.00	$30.58	$41.55	$12.47	$41.25	$0.00	$142.85	$127.85	$4.96	4.0%

LIFELINE SERVICE RATE R-04-01 FROZEN

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
					$6.90	$0.05700	$0.05700	$0.05700	$0.025698	$0.00682			
Small	381	381	0	0	$6.90	$21.72	$0.00	$0.00	$9.79	$2.60	$41.01	$28.71	-30.0%
Medium	604	500	104	0	$6.90	$28.50	$5.93	$0.00	$15.52	$4.12	$60.97	$45.73	-25.0%
Large	913	500	413	0	$6.90	$28.50	$23.54	$0.00	$23.46	$6.23	$88.63	$66.47	-25.0%
XLg	1,197	500	500	197	$6.90	$28.50	$28.50	$11.23	$30.76	$8.16	$114.05	$96.94	-15.0%
AnnAvg	560	500	60	0	$6.90	$28.50	$3.42	$0.00	$14.39	$3.82	$57.03	$39.92	-30.0%
ResAvg	785	500	285	0	$6.90	$28.50	$16.25	$0.00	$20.17	$5.35	$77.17	$57.88	-25.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$17.00	$0.06116	$0.08310	$0.08310	$0.032537	$0.00000				
Small	381	381	0	0	$17.00	$23.30	$0.00	$0.00	$12.40	$0.00	$52.70	$21.70	-$7.01	-24.4%
Medium	604	500	104	0	$17.00	$30.58	$8.64	$0.00	$19.65	$0.00	$75.87	$44.87	-$0.86	-1.9%
Large	913	500	413	0	$17.00	$30.58	$34.32	$0.00	$29.71	$0.00	$111.61	$80.61	$14.14	21.3%
XLg	1,197	500	500	197	$17.00	$30.58	$41.55	$16.37	$38.95	$0.00	$144.45	$113.45	$16.51	17.0%
AnnAvg	560	500	60	0	$17.00	$30.58	$4.99	$0.00	$18.22	$0.00	$70.79	$39.79	-$0.13	-0.3%
ResAvg	785	500	285	0	$17.00	$30.58	$23.68	$0.00	$25.54	$0.00	$96.80	$65.80	$7.92	13.7%

LIFELINE SERVICE RATE R-04-01 FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
					$6.90	$0.06110	$0.06110	$0.06110	$0.033198	$0.00682			
Small	552	500	52	0	$6.90	$30.55	$3.18	$0.00	$18.33	$3.76	$62.72	$43.90	-30.0%
Medium	894	500	394	0	$6.90	$30.55	$24.04	$0.00	$29.66	$6.09	$97.24	$72.93	-25.0%
Large	1,280	500	500	280	$6.90	$30.55	$30.55	$17.11	$42.49	$8.73	$136.33	$115.88	-15.0%
XLg	1,550	500	500	550	$6.90	$30.55	$30.55	$33.61	$51.46	$10.57	$163.64	$163.64	0.0%
AnnAvg	560	500	60	0	$6.90	$30.55	$3.67	$0.00	$18.59	$3.82	$63.53	$44.47	-30.0%
ResAvg	1,150	500	500	150	$6.90	$30.55	$30.55	$9.17	$38.18	$7.84	$123.19	$104.71	-15.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$17.00	$0.06116	$0.08310	$0.08310	$0.035868	$0.00000				
Small	552	500	52	0	$17.00	$30.58	$4.32	$0.00	$19.80	$0.00	$71.70	$40.70	-$3.20	-7.3%
Medium	894	500	394	0	$17.00	$30.58	$32.70	$0.00	$32.05	$0.00	$112.33	$81.33	$8.40	11.5%
Large	1,280	500	500	280	$17.00	$30.58	$41.55	$23.27	$45.91	$0.00	$158.31	$127.31	$11.43	9.9%
XLg	1,550	500	500	550	$17.00	$30.58	$41.55	$45.71	$55.60	$0.00	$190.44	$159.44	-$4.20	-2.6%
AnnAvg	560	500	60	0	$17.00	$30.58	$4.99	$0.00	$20.09	$0.00	$72.66	$41.66	-$2.81	-6.3%
ResAvg	1,150	500	500	150	$17.00	$30.58	$41.55	$12.47	$41.25	$0.00	$142.85	$111.85	$7.14	6.8%

LIFELINE SERVICE RATE R-05-01 FROZEN

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
					$6.90	$0.05700	$0.05700	$0.05700	$0.025698	$0.00682			
Small	480	480	0	0	$6.90	$27.36	$0.00	$0.00	$12.34	$3.27	$49.87	$39.90	-20.0%
Medium	719	500	219	0	$6.90	$28.50	$12.48	$0.00	$18.48	$4.90	$71.26	$60.57	-15.0%
Large	1,050	500	500	50	$6.90	$28.50	$28.50	$2.85	$26.98	$7.16	$100.89	$100.89	0.0%
XLg	1,314	500	500	314	$6.90	$28.50	$28.50	$17.90	$33.77	$8.96	$124.53	$124.53	0.0%
AnnAvg	659	500	159	0	$6.90	$28.50	$9.09	$0.00	$16.94	$4.50	$65.93	$56.04	-15.0%
ResAvg	785	500	285	0	$6.90	$28.50	$16.25	$0.00	$20.17	$5.35	$77.17	$65.59	-15.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$17.00	$0.06116	$0.08310	$0.08310	$0.032537	$0.00000				
Small	480	480	0	0	$17.00	$29.36	$0.00	$0.00	$15.62	$0.00	$61.98	$46.98	$7.08	17.7%
Medium	719	500	219	0	$17.00	$30.58	$18.20	$0.00	$23.39	$0.00	$89.17	$74.17	$13.60	22.5%
Large	1,050	500	500	50	$17.00	$30.58	$41.55	$4.16	$34.16	$0.00	$127.45	$112.45	$11.56	11.5%
XLg	1,314	500	500	314	$17.00	$30.58	$41.55	$26.09	$42.75	$0.00	$157.97	$142.97	$18.44	14.8%
AnnAvg	659	500	159	0	$17.00	$30.58	$13.25	$0.00	$21.45	$0.00	$82.28	$67.28	$11.24	20.1%
ResAvg	785	500	285	0	$17.00	$30.58	$23.68	$0.00	$25.54	$0.00	$96.80	$81.80	$16.21	24.7%

LIFELINE SERVICE RATE R-05-01 FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
					$6.90	$0.06110	$0.06110	$0.06110	$0.033198	$0.00682			
Small	670	500	170	0	$6.90	$30.55	$10.39	$0.00	$22.24	$4.57	$74.65	$63.45	-15.0%
Medium	1,012	500	500	12	$6.90	$30.55	$30.55	$0.70	$33.58	$6.90	$109.18	$109.18	0.0%
Large	1,460	500	500	460	$6.90	$30.55	$30.55	$28.11	$48.47	$9.96	$154.54	$154.54	0.0%
XLg	1,796	500	500	796	$6.90	$30.55	$30.55	$48.64	$59.62	$12.25	$188.51	$188.51	0.0%
AnnAvg	659	500	159	0	$6.90	$30.55	$9.74	$0.00	$21.89	$4.50	$73.58	$62.54	-15.0%
ResAvg	1,150	500	500	150	$6.90	$30.55	$30.55	$9.17	$38.18	$7.84	$123.19	$123.19	0.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$17.00	$0.06116	$0.08310	$0.08310	$0.035868	$0.00000				
Small	670	500	170	0	$17.00	$30.58	$14.13	$0.00	$24.03	$0.00	$85.74	$70.74	$7.29	11.5%
Medium	1,012	500	500	12	$17.00	$30.58	$41.55	$0.96	$36.28	$0.00	$126.37	$111.37	$2.19	2.0%
Large	1,460	500	500	460	$17.00	$30.58	$41.55	$38.23	$52.37	$0.00	$179.73	$164.73	$10.19	6.6%
XLg	1,796	500	500	796	$17.00	$30.58	$41.55	$66.15	$64.42	$0.00	$219.70	$204.70	$16.19	8.6%
AnnAvg	659	500	159	0	$17.00	$30.58	$13.25	$0.00	$23.65	$0.00	$84.48	$69.48	$6.94	11.1%
ResAvg	1,150	500	500	150	$17.00	$30.58	$41.55	$12.47	$41.25	$0.00	$142.85	$127.85	$4.66	3.8%

LIFELINE SERVICE RATE R-06-01 FROZEN

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
					$6.90	$0.05700	$0.05700	$0.05700	$0.025698	$0.00682			
Small	490	490	0	0	$6.90	$27.93	$0.00	$0.00	$12.59	$3.34	$50.76	$41.76	-17.7%
Medium	769	500	269	0	$6.90	$28.50	$15.33	$0.00	$19.76	$5.24	$75.73	$66.73	-11.9%
Large	1,127	500	500	127	$6.90	$28.50	$28.50	$7.24	$28.96	$7.69	$107.79	$98.79	-8.3%
XLg	1,400	500	500	400	$6.90	$28.50	$28.50	$22.80	$35.98	$9.55	$132.23	$123.23	-6.8%
AnnAvg	730	500	230	0	$6.90	$28.50	$13.08	$0.00	$18.75	$4.98	$72.21	$63.21	-12.5%
ResAvg	785	500	285	0	$6.90	$28.50	$16.25	$0.00	$20.17	$5.35	$77.17	$68.17	-11.7%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$17.00	$0.06116	$0.08310	$0.08310	$0.032537	$0.00000				
Small	490	490	0	0	$17.00	$29.97	$0.00	$0.00	$15.94	$0.00	$62.91	$47.91	$6.15	14.7%
Medium	769	500	269	0	$17.00	$30.58	$22.35	$0.00	$25.02	$0.00	$94.95	$79.95	$13.22	19.8%
Large	1,127	500	500	127	$17.00	$30.58	$41.55	$10.55	$36.67	$0.00	$136.35	$121.35	$22.56	22.8%
XLg	1,400	500	500	400	$17.00	$30.58	$41.55	$33.24	$45.55	$0.00	$167.92	$152.92	$29.69	24.1%
AnnAvg	730	500	230	0	$17.00	$30.58	$19.07	$0.00	$23.74	$0.00	$90.39	$75.39	$12.18	19.3%
ResAvg	785	500	285	0	$17.00	$30.58	$23.68	$0.00	$25.54	$0.00	$96.80	$81.80	$13.63	20.0%

LIFELINE SERVICE RATE R-06-01 FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
					$6.90	$0.06110	$0.06110	$0.06110	$0.033198	$0.00682			
Small	758	500	258	0	$6.90	$30.55	$15.76	$0.00	$25.16	$5.17	$83.54	$74.54	-10.8%
Medium	1,220	500	500	220	$6.90	$30.55	$30.55	$13.44	$40.50	$8.32	$130.26	$121.26	-6.9%
Large	1,737	500	500	737	$6.90	$30.55	$30.55	$45.03	$57.66	$11.85	$182.54	$173.54	-4.9%
XLg	2,092	500	500	1,092	$6.90	$30.55	$30.55	$66.72	$69.45	$14.27	$218.44	$209.44	-4.1%
AnnAvg	730	500	230	0	$6.90	$30.55	$14.02	$0.00	$24.22	$4.98	$80.67	$71.67	-11.2%
ResAvg	1,150	500	500	150	$6.90	$30.55	$30.55	$9.17	$38.18	$7.84	$123.19	$114.19	-7.3%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$17.00	$0.06116	$0.08310	$0.08310	$0.035868	$0.00000				
Small	758	500	258	0	$17.00	$30.58	$21.44	$0.00	$27.19	$0.00	$96.21	$81.21	$6.67	8.9%
Medium	1,220	500	500	220	$17.00	$30.58	$41.55	$18.28	$43.76	$0.00	$151.17	$136.17	$14.91	12.3%
Large	1,737	500	500	737	$17.00	$30.58	$41.55	$61.24	$62.30	$0.00	$212.67	$197.67	$24.13	13.9%
XLg	2,092	500	500	1,092	$17.00	$30.58	$41.55	$90.75	$75.04	$0.00	$254.92	$239.92	$30.48	14.6%
AnnAvg	730	500	230	0	$17.00	$30.58	$19.07	$0.00	$26.17	$0.00	$92.82	$77.82	$6.15	8.6%
ResAvg	1,150	500	500	150	$17.00	$30.58	$41.55	$12.47	$41.25	$0.00	$142.85	$127.85	$13.66	12.0%

LIFELINE SERVICE RATE R-08-01 FROZEN

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
					$6.90	$0.05700	$0.05700	$0.05700	$0.025698	$0.00682			
Small	688	500	188	0	$6.90	$28.50	$10.72	$0.00	$17.68	$4.69	$68.49	$44.52	-35.0%
Medium	1,016	500	500	16	$6.90	$28.50	$28.50	$0.91	$26.11	$6.93	$97.85	$68.50	-30.0%
Large	1,423	500	500	423	$6.90	$28.50	$28.50	$24.11	$36.57	$9.70	$134.28	$94.00	-30.0%
XLg	1,720	500	500	720	$6.90	$28.50	$28.50	$41.04	$44.20	$11.73	$160.87	$112.61	-30.0%
AnnAvg	974	500	474	0	$6.90	$28.50	$27.04	$0.00	$25.04	$6.64	$94.12	$61.18	-35.0%
ResAvg	785	500	285	0	$6.90	$28.50	$16.25	$0.00	$20.17	$5.35	$77.17	$50.16	-35.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$17.00	$0.06116	$0.08310	$0.08310	$0.032537	$0.00000				
Small	688	500	188	0	$17.00	$30.58	$15.62	$0.00	$22.39	$0.00	$85.59	$45.59	$1.07	2.4%
Medium	1,016	500	500	16	$17.00	$30.58	$41.55	$1.33	$33.06	$0.00	$123.52	$83.52	$15.02	21.9%
Large	1,423	500	500	423	$17.00	$30.58	$41.55	$35.15	$46.30	$0.00	$170.58	$130.58	$36.58	38.9%
XLg	1,720	500	500	720	$17.00	$30.58	$41.55	$59.83	$55.96	$0.00	$204.92	$164.92	$52.31	46.5%
AnnAvg	974	500	474	0	$17.00	$30.58	$39.42	$0.00	$31.70	$0.00	$118.70	$78.70	$17.52	28.6%
ResAvg	785	500	285	0	$17.00	$30.58	$23.68	$0.00	$25.54	$0.00	$96.80	$56.80	$6.64	13.2%

LIFELINE SERVICE RATE R-08-01 FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
					$6.90	$0.06110	$0.06110	$0.06110	$0.033198	$0.00682			
Small	1,090	500	500	90	$6.90	$30.55	$30.55	$5.50	$36.19	$7.43	$117.12	$81.98	-30.0%
Medium	1,614	500	500	614	$6.90	$30.55	$30.55	$37.52	$53.58	$11.01	$170.11	$119.08	-30.0%
Large	2,170	500	500	1,170	$6.90	$30.55	$30.55	$71.49	$72.04	$14.80	$226.33	$203.70	-10.0%
XLg	2,511	500	500	1,511	$6.90	$30.55	$30.55	$92.32	$83.36	$17.13	$260.81	$234.73	-10.0%
AnnAvg	974	500	474	0	$6.90	$30.55	$28.98	$0.00	$32.35	$6.64	$105.42	$68.52	-35.0%
ResAvg	1,150	500	500	150	$6.90	$30.55	$30.55	$9.17	$38.18	$7.84	$123.19	$86.23	-30.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$17.00	$0.06116	$0.08310	$0.08310	$0.035868	$0.00000				
Small	1,090	500	500	90	$17.00	$30.58	$41.55	$7.48	$39.10	$0.00	$135.71	$95.71	$13.73	16.7%
Medium	1,614	500	500	614	$17.00	$30.58	$41.55	$51.02	$57.89	$0.00	$198.04	$158.04	$38.96	32.7%
Large	2,170	500	500	1,170	$17.00	$30.58	$41.55	$97.23	$77.83	$0.00	$264.19	$224.19	$20.49	10.1%
XLg	2,511	500	500	1,511	$17.00	$30.58	$41.55	$125.56	$90.06	$0.00	$304.75	$264.75	$30.02	12.8%
AnnAvg	974	500	474	0	$17.00	$30.58	$39.42	$0.00	$34.95	$0.00	$121.95	$81.95	$13.43	19.6%
ResAvg	1,150	500	500	150	$17.00	$30.58	$41.55	$12.47	$41.25	$0.00	$142.85	$102.85	$16.62	19.3%

RESIDENTIAL SERVICE TIME OF USE RATE R-80

Winter

	BILL IMPACTS CURRENT RATES										
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill
		500	1000	>1000		500	1000	>1000			
On-Peak	0.25				$11.50	$0.05680	$0.05680	$0.05680	$0.032893	$0.00682	
Off-Peak	0.75					$0.04180	$0.04180	$0.04180	$0.027092		
Small	796	500	296	0	$11.50	$22.76	$13.48	$0.00	$22.71	$5.43	$75.88
Medium	1,196	500	500	196	$11.50	$22.76	$22.76	$8.92	$34.13	$8.16	$108.23
Large	1,678	500	500	678	$11.50	$22.76	$22.76	$30.87	$47.88	$11.44	$147.21
XLg	2,047	500	500	1,047	$11.50	$22.76	$22.76	$47.67	$58.41	$13.96	$177.06
AnnAvg	1,125	500	500	125	$11.50	$22.76	$22.76	$5.70	$32.10	$7.67	$102.49
ResAvg	785	500	285	0	$11.50	$22.76	$12.97	$0.00	$22.40	$5.35	$74.98

	BILL IMPACTS PROPOSED RATES												
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill		
		500	1000	>1000		500	1000	>1000					
On-Peak	0.25				$17.00	$0.06116	$0.08310	$0.08310	$0.033893	$0.00000			
Off-Peak	0.75					$0.06116	$0.08310	$0.08310	$0.028092			$ Change	% Change
Small	796	500	296	0	$17.00	$30.58	$24.60	$0.00	$23.51	$0.00	$95.69	$19.81	26.1%
Medium	1,196	500	500	196	$17.00	$30.58	$41.55	$16.29	$35.32	$0.00	$140.74	$32.51	30.0%
Large	1,678	500	500	678	$17.00	$30.58	$41.55	$56.34	$49.56	$0.00	$195.03	$47.82	32.5%
XLg	2,047	500	500	1,047	$17.00	$30.58	$41.55	$87.01	$60.45	$0.00	$236.59	$59.53	33.6%
AnnAvg	1,125	500	500	125	$17.00	$30.58	$41.55	$10.40	$33.23	$0.00	$132.76	$30.27	29.5%
ResAvg	785	500	285	0	$17.00	$30.58	$23.68	$0.00	$23.18	$0.00	$94.44	$19.46	26.0%

RESIDENTIAL SERVICE TIME OF USE RATE R-80

Summer

	BILL IMPACTS CURRENT RATES										
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill
		500	1000	>1000	$11.50	500	1000	>1000			
On-Peak	0.23					$0.06680	$0.06680	$0.06680	$0.050669	$0.00682	
Off-Peak	0.77					$0.05180	$0.05180	$0.05180	$0.026679		
Small	1,249	500	500	249	$11.50	$27.61	$27.61	$13.72	$40.13	$8.51	$129.08
Medium	1,881	500	500	881	$11.50	$27.61	$27.61	$48.65	$60.46	$12.83	$188.66
Large	2,539	500	500	1,539	$11.50	$27.61	$27.61	$84.98	$81.61	$17.32	$250.63
XLg	3,011	500	500	2,011	$11.50	$27.61	$27.61	$111.04	$96.78	$20.54	$295.08
AnnAvg	1,125	500	500	125	$11.50	$27.61	$27.61	$6.91	$36.16	$7.67	$117.46
ResAvg	1,150	500	500	150	$11.50	$27.61	$27.61	$8.28	$36.96	$7.84	$119.80

	BILL IMPACTS PROPOSED RATES												
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill		
		500	1000	>1000		500	1000	>1000					
On-Peak	0.23				$17.00	$0.06116	$0.08310	$0.08310	$0.051660	$0.00000			
Off-Peak	0.77					$0.06116	$0.08310	$0.08310	$0.026750			$ Change	% Change
Small	1,249	500	500	249	$17.00	$30.58	$41.55	$20.65	$40.48	$0.00	$150.26	$21.18	16.4%
Medium	1,881	500	500	881	$17.00	$30.58	$41.55	$73.21	$60.99	$0.00	$223.33	$34.67	18.4%
Large	2,539	500	500	1,539	$17.00	$30.58	$41.55	$127.89	$82.32	$0.00	$299.34	$48.71	19.4%
XLg	3,011	500	500	2,011	$17.00	$30.58	$41.55	$167.11	$97.62	$0.00	$353.86	$58.78	19.9%
AnnAvg	1,125	500	500	125	$17.00	$30.58	$41.55	$10.40	$36.48	$0.00	$136.01	$18.55	15.8%
ResAvg	1,150	500	500	150	$17.00	$30.58	$41.55	$12.47	$37.29	$0.00	$138.89	$19.09	15.9%

RESIDENTIAL SERVICE DEMAND TIME OF USE

WINTER

BILL IMPACTS CURRENT R-80 RATES

	Load Factor	kWh	Delivery (kWh) TIERS			kW	Delivery (kW)		Basic Service Charge	Delivery			Delivery (Demand)		Base Fuel	PPFAC	Net Bill
			500	1000	>1000				$11.50	500	1000	>1000					
On-Peak		0.25								$0.05680	$0.05680	$0.05680			$0.032893	$0.00682	
Off-Peak		0.75								$0.04180	$0.04180	$0.04180			$0.027092		
Small	0.22	796	500	296	0	4.9			$11.50	$22.76	$13.48	$0.00			$22.71	$5.43	$75.88
Medium	0.26	1,196	500	500	196	6.4			$11.50	$22.76	$22.76	$8.92			$34.13	$8.16	$108.23
Large	0.29	1,678	500	500	678	8.0			$11.50	$22.76	$22.76	$30.87			$47.88	$11.44	$147.21
XLg	0.31	2,047	500	500	1,047	9.1			$11.50	$22.76	$22.76	$47.67			$58.41	$13.96	$177.06
AnnAvg	0.25	1,125	500	500	125	6.1			$11.50	$22.76	$22.76	$5.70			$32.10	$7.67	$102.49
ResAvg	0.22	785	500	285	0	4.9			$11.50	$22.76	$12.97	$0.00			$22.40	$5.35	$74.98

BILL IMPACTS PROPOSED RATES

	Load Factor	kWh	Delivery (kWh) TIERS			kW	Delivery (kW) TIERS		Basic Service Charge	Delivery			Delivery (Demand)		Base Fuel	PPFAC	Net Bill		
			500	1000	>1000		7.0	> 7.0		500	1000	>1000	7.0	> 7.0					
On-Peak		0.25							$17.00	$0.02492	$0.02492	$0.02492	$7.40	$11.90	$0.033893	$0.00000			
Off-Peak		0.75								$0.02492	$0.02492	$0.02492			$0.028092			$ Change	% Change
Small	0.22	796	500	296	0	4.9	4.9	0.0	$17.00	$12.46	$7.38	$0.00	$36.19	$0.00	$23.51	$0.00	$96.54	$20.66	27.2%
Medium	0.26	1,196	500	500	196	6.4	6.4	0.0	$17.00	$12.46	$12.46	$4.88	$47.29	$0.00	$35.32	$0.00	$129.41	$21.18	19.6%
Large	0.29	1,678	500	500	678	8.0	7.0	1.0	$17.00	$12.46	$12.46	$16.90	$51.80	$11.54	$49.56	$0.00	$171.72	$24.51	16.6%
XLg	0.31	2,047	500	500	1,047	9.1	7.0	2.1	$17.00	$12.46	$12.46	$26.09	$51.80	$24.75	$60.45	$0.00	$205.01	$27.95	15.8%
AnnAvg	0.25	1,125	500	500	125	6.1	6.1	0.0	$17.00	$12.46	$12.46	$3.12	$45.44	$0.00	$33.23	$0.00	$123.71	$21.22	20.7%
ResAvg	0.22	785	500	285	0	4.9	4.9	0.0	$17.00	$12.46	$7.10	$0.00	$35.89	$0.00	$23.18	$0.00	$95.63	$20.65	27.5%

RESIDENTIAL SERVICE DEMAND TIME OF USE

SUMMER

BILL IMPACTS CURRENT R-80 RATES

	Load Factor	kWh	Delivery (kWh) TIERS			kW	Delivery (kW)		Basic Service Charge	Delivery			Delivery (Demand)		Base Fuel	PPFAC	Net Bill
			500	1000	>1000				$11.50	500	1000	>1000					
On-Peak		0.23								$0.06680	$0.06680	$0.06680			$0.050669	$0.00682	
Off-Peak		0.77								$0.05180	$0.05180	$0.05180			$0.026679		
Small	0.26	1,249	500	500	249	6.6			$11.50	$27.61	$27.61	$13.72			$40.13	$8.51	$129.08
Medium	0.30	1,881	500	500	881	8.6			$11.50	$27.61	$27.61	$48.65			$60.46	$12.83	$188.66
Large	0.33	2,539	500	500	1,539	10.5			$11.50	$27.61	$27.61	$84.98			$81.61	$17.32	$250.63
XLg	0.35	3,011	500	500	2,011	11.7			$11.50	$27.61	$27.61	$111.04			$96.78	$20.54	$295.08
AnnAvg	0.25	1,125	500	500	125	6.1			$11.50	$27.61	$27.61	$6.91			$36.16	$7.67	$117.46
ResAvg	0.25	1,150	500	500	150	6.2			$11.50	$27.61	$27.61	$8.28			$36.96	$7.84	$119.80

BILL IMPACTS PROPOSED RATES

	Load Factor	kWh	Delivery (kWh) TIERS			kW	Delivery (kW) TIERS		Basic Service Charge	Delivery			Delivery (Demand)		Base Fuel	PPFAC	Net Bill		
			500	1000	>1000		7.0	> 7.0		500	1000	>1000	7.0	> 7.0					
On-Peak		0.23							$17.00	$0.02492	$0.02492	$0.02492	$7.40	$11.90	$0.051660	$0.00000			
Off-Peak		0.77								$0.02492	$0.02492	$0.02492			$0.026750			$ Change	% Change
Small	0.26	1,249	500	500	249	6.6	6.6	0.0	$17.00	$12.46	$12.46	$6.19	$48.62	$0.00	$40.48	$0.00	$137.21	$8.13	6.3%
Medium	0.30	1,881	500	500	881	8.6	7.0	1.6	$17.00	$12.46	$12.46	$21.95	$51.80	$18.92	$60.99	$0.00	$195.58	$6.92	3.7%
Large	0.33	2,539	500	500	1,539	10.5	7.0	3.5	$17.00	$12.46	$12.46	$38.35	$51.80	$41.17	$82.32	$0.00	$255.56	$4.93	2.0%
XLg	0.35	3,011	500	500	2,011	11.7	7.0	4.7	$17.00	$12.46	$12.46	$50.11	$51.80	$55.81	$97.62	$0.00	$297.26	$2.18	0.7%
AnnAvg	0.25	1,125	500	500	125	6.1	6.1	0.0	$17.00	$12.46	$12.46	$3.12	$45.44	$0.00	$36.48	$0.00	$126.96	$9.50	8.1%
ResAvg	0.25	1,150	500	500	150	6.2	6.2	0.0	$17.00	$12.46	$12.46	$3.74	$46.03	$0.00	$37.29	$0.00	$128.98	$9.18	7.7%

LIFELINE RESIDENTIAL SERVICE TIME OF USE RATE R-80L

Winter

	BILL IMPACTS CURRENT RATES												
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.25				$11.50	$0.05680	$0.05680	$0.05680	$0.032893	$0.00682			
Off-Peak	0.75					$0.04180	$0.04180	$0.04180	$0.027092				
Small	496	496	0	0	$11.50	$22.56	$0.00	$0.00	$14.14	$3.38	$51.58	$42.58	-17.4%
Medium	949	500	449	0	$11.50	$22.76	$20.44	$0.00	$27.08	$6.47	$88.25	$79.25	-10.2%
Large	1,507	500	500	507	$11.50	$22.76	$22.76	$23.08	$43.00	$10.28	$133.38	$124.38	-6.7%
XLg	1,917	500	500	917	$11.50	$22.76	$22.76	$41.75	$54.70	$13.07	$166.54	$157.54	-5.4%
AnnAvg	816	500	316	0	$11.50	$22.76	$14.37	$0.00	$23.27	$5.56	$77.46	$68.46	-11.6%
ResAvg	785	500	285	0	$11.50	$22.76	$12.97	$0.00	$22.40	$5.35	$74.98	$65.98	-12.0%

	BILL IMPACTS PROPOSED RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000						
On-Peak	0.25				$17.00	$0.06116	$0.08310	$0.08310	$0.033893	$0.00000				
Off-Peak	0.75					$0.06116	$0.08310	$0.08310	$0.028092				$ Change	% Change
Small	496	496	0	0	$17.00	$30.30	$0.00	$0.00	$14.63	$0.00	$61.93	$46.93	$4.35	10.2%
Medium	949	500	449	0	$17.00	$30.58	$37.31	$0.00	$28.03	$0.00	$112.92	$97.92	$18.67	23.6%
Large	1,507	500	500	507	$17.00	$30.58	$41.55	$42.13	$44.51	$0.00	$175.77	$160.77	$36.39	29.3%
XLg	1,917	500	500	917	$17.00	$30.58	$41.55	$76.20	$56.61	$0.00	$221.94	$206.94	$49.40	31.4%
AnnAvg	816	500	316	0	$17.00	$30.58	$26.24	$0.00	$24.09	$0.00	$97.91	$82.91	$14.45	21.1%
ResAvg	785	500	285	0	$17.00	$30.58	$23.68	$0.00	$23.18	$0.00	$94.44	$79.44	$13.46	20.4%

LIFELINE RESIDENTIAL SERVICE TIME OF USE RATE R-80L

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000	$11.50	500	1000	>1000					
On-Peak	0.23					$0.06680	$0.06680	$0.06680	$0.050669	$0.00682			
Off-Peak	0.77					$0.05180	$0.05180	$0.05180	$0.026679				
Small	754	500	254	0	$11.50	$27.61	$14.02	$0.00	$24.24	$5.14	$82.51	$73.51	-10.9%
Medium	1,293	500	500	293	$11.50	$27.61	$27.61	$16.18	$41.56	$8.82	$133.28	$124.28	-6.8%
Large	2,020	500	500	1,020	$11.50	$27.61	$27.61	$56.32	$64.93	$13.78	$201.75	$192.75	-4.5%
XLg	2,353	500	500	1,353	$11.50	$27.61	$27.61	$74.71	$75.63	$16.05	$233.11	$224.11	-3.9%
AnnAvg	816	500	316	0	$11.50	$27.61	$17.43	$0.00	$26.22	$5.56	$88.32	$79.32	-10.2%
ResAvg	1,150	500	500	150	$11.50	$27.61	$27.61	$8.28	$36.96	$7.84	$119.80	$110.80	-7.5%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.23				$17.00	$0.06116	$0.08310	$0.08310	$0.051660	$0.00000				
Off-Peak	0.77					$0.06116	$0.08310	$0.08310	$0.026750					
Small	754	500	254	0	$17.00	$30.58	$21.11	$0.00	$24.45	$0.00	$93.14	$78.14	$4.63	6.3%
Medium	1,293	500	500	293	$17.00	$30.58	$41.55	$24.35	$41.92	$0.00	$155.40	$140.40	$16.12	13.0%
Large	2,020	500	500	1,020	$17.00	$30.58	$41.55	$84.76	$65.49	$0.00	$239.38	$224.38	$31.63	16.4%
XLg	2,353	500	500	1,353	$17.00	$30.58	$41.55	$112.43	$76.29	$0.00	$277.85	$262.85	$38.74	17.3%
AnnAvg	816	500	316	0	$17.00	$30.58	$26.24	$0.00	$26.45	$0.00	$100.27	$85.27	$5.95	7.5%
ResAvg	1,150	500	500	150	$17.00	$30.58	$41.55	$12.47	$37.29	$0.00	$138.89	$123.89	$13.09	11.8%

LIFELINE SERVICE TIME OF USE RATE R-04-21 FROZEN

Winter

	BILL IMPACTS CURRENT RATES												
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.23				$8.86	$0.06520	$0.06520	$0.06520	$0.040698	$0.00682			
Off-Peak	0.77					$0.03300	$0.03300	$0.03300	$0.020698				
Small	717	500	217	0	$8.86	$20.23	$8.78	$0.00	$18.16	$4.89	$60.92	$45.69	-25.0%
Medium	857	500	357	0	$8.86	$20.23	$14.44	$0.00	$21.71	$5.84	$71.08	$53.31	-25.0%
Large	1,060	500	500	60	$8.86	$20.23	$20.23	$2.43	$26.85	$7.23	$85.83	$72.96	-15.0%
XLg	1,545	500	500	545	$8.86	$20.23	$20.23	$22.05	$39.14	$10.54	$121.05	$121.05	0.0%
AnnAvg	950	500	450	0	$8.86	$20.23	$18.19	$0.00	$24.05	$6.48	$77.81	$58.36	-25.0%
ResAvg	785	500	285	0	$8.86	$20.23	$11.53	$0.00	$19.89	$5.35	$65.86	$49.40	-25.0%

	BILL IMPACTS PROPOSED RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000						
On-Peak	0.25				$17.00	$0.06116	$0.08310	$0.08310	$0.056000	$0.00000				
Off-Peak	0.75					$0.06116	$0.08310	$0.08310	$0.028092				$ Change	% Change
Small	717	500	217	0	$17.00	$30.58	$18.03	$0.00	$25.11	$0.00	$90.72	$59.72	$14.03	30.7%
Medium	857	500	357	0	$17.00	$30.58	$29.67	$0.00	$30.02	$0.00	$107.27	$76.27	$22.96	43.1%
Large	1,060	500	500	60	$17.00	$30.58	$41.55	$4.99	$37.13	$0.00	$131.25	$100.25	$27.29	37.4%
XLg	1,545	500	500	545	$17.00	$30.58	$41.55	$45.29	$54.11	$0.00	$188.53	$157.53	$36.48	30.1%
AnnAvg	950	500	450	0	$17.00	$30.58	$37.36	$0.00	$33.26	$0.00	$118.20	$87.20	$28.84	49.4%
ResAvg	785	500	285	0	$17.00	$30.58	$23.68	$0.00	$27.49	$0.00	$98.75	$67.75	$18.35	37.1%

LIFELINE SERVICE TIME OF USE RATE R-04-21 FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000	$8.86	500	1000	>1000					
On-Peak	0.37					$0.07880	$0.07880	$0.07880	$0.053198	$0.00682			
Off-Peak	0.63					$0.03010	$0.03010	$0.03010	$0.023198				
Small	1,178	500	500	178	$8.86	$24.17	$24.17	$8.60	$40.56	$8.03	$114.39	$97.23	-15.0%
Medium	1,990	500	500	990	$8.86	$24.17	$24.17	$47.85	$68.52	$13.57	$187.14	$187.14	0.0%
Large	2,154	500	500	1,154	$8.86	$24.17	$24.17	$55.78	$74.17	$14.69	$201.84	$201.84	0.0%
XLg	2,260	500	500	1,260	$8.86	$24.17	$24.17	$60.90	$77.82	$15.41	$211.33	$211.33	0.0%
AnnAvg	950	500	450	0	$8.86	$24.17	$21.73	$0.00	$32.70	$6.48	$93.94	$70.46	-25.0%
ResAvg	1,150	500	500	150	$8.86	$24.17	$24.17	$7.25	$39.60	$7.84	$111.89	$95.11	-15.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.23				$17.00	$0.06116	$0.08310	$0.08310	$0.051660	$0.00000				
Off-Peak	0.77					$0.06116	$0.08310	$0.08310	$0.026750					
Small	1,178	500	500	178	$17.00	$30.58	$41.55	$14.79	$38.19	$0.00	$142.11	$111.11	$13.88	14.3%
Medium	1,990	500	500	990	$17.00	$30.58	$41.55	$82.27	$64.52	$0.00	$235.92	$204.92	$17.78	9.5%
Large	2,154	500	500	1,154	$17.00	$30.58	$41.55	$95.90	$69.84	$0.00	$254.87	$223.87	$22.03	10.9%
XLg	2,260	500	500	1,260	$17.00	$30.58	$41.55	$104.71	$73.28	$0.00	$267.12	$236.12	$24.79	11.7%
AnnAvg	950	500	450	0	$17.00	$30.58	$37.36	$0.00	$30.79	$0.00	$115.73	$84.73	$14.27	20.3%
ResAvg	1,150	500	500	150	$17.00	$30.58	$41.55	$12.47	$37.29	$0.00	$138.89	$107.89	$12.78	13.4%

LIFELINE SERVICE TIME OF USE RATE R-05-21 FROZEN

Winter

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.25				$8.86	$0.06520	$0.06520	$0.06520	$0.040698	$0.00682			
Off-Peak	0.75					$0.03300	$0.03300	$0.03300	$0.020698				
Small	984	500	484	0	$8.86	$20.51	$19.84	$0.00	$25.26	$6.71	$81.18	$69.00	-15.0%
Medium	1,203	500	500	203	$8.86	$20.51	$20.51	$8.33	$30.90	$8.20	$97.31	$97.31	0.0%
Large	1,447	500	500	447	$8.86	$20.51	$20.51	$18.34	$37.17	$9.87	$115.26	$115.26	0.0%
XLg	1,690	500	500	690	$8.86	$20.51	$20.51	$28.31	$43.41	$11.53	$133.13	$133.13	0.0%
AnnAvg	1,145	500	500	145	$8.86	$20.51	$20.51	$5.93	$29.40	$7.81	$93.02	$93.02	0.0%
ResAvg	785	500	285	0	$8.86	$20.51	$11.69	$0.00	$20.16	$5.35	$66.57	$56.58	-15.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.25				$17.00	$0.06116	$0.08310	$0.08310	$0.056000	$0.00000				
Off-Peak	0.75					$0.06116	$0.08310	$0.08310	$0.028092					
Small	984	500	484	0	$17.00	$30.58	$40.18	$0.00	$34.45	$0.00	$122.21	$107.21	$38.21	55.4%
Medium	1,203	500	500	203	$17.00	$30.58	$41.55	$16.87	$42.13	$0.00	$148.13	$133.13	$35.82	36.8%
Large	1,447	500	500	447	$17.00	$30.58	$41.55	$37.15	$50.68	$0.00	$176.96	$161.96	$46.70	40.5%
XLg	1,690	500	500	690	$17.00	$30.58	$41.55	$57.34	$59.19	$0.00	$205.66	$190.66	$57.53	43.2%
AnnAvg	1,145	500	500	145	$17.00	$30.58	$41.55	$12.01	$40.08	$0.00	$141.22	$126.22	$33.20	35.7%
ResAvg	785	500	285	0	$17.00	$30.58	$23.68	$0.00	$27.49	$0.00	$98.75	$83.75	$27.17	48.0%

LIFELINE SERVICE TIME OF USE RATE R-05-21 FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000	$8.86	500	1000	>1000					
On-Peak	0.38					$0.07880	$0.07880	$0.07880	$0.053198	$0.00682			
Off-Peak	0.62					$0.03010	$0.03010	$0.03010	$0.023198				
Small	1,376	500	500	376	$8.86	$24.24	$24.24	$18.23	$47.50	$9.38	$132.45	$132.45	0.0%
Medium	1,897	500	500	897	$8.86	$24.24	$24.24	$43.49	$65.49	$12.94	$179.26	$179.26	0.0%
Large	2,029	500	500	1,029	$8.86	$24.24	$24.24	$49.89	$70.04	$13.84	$191.11	$191.11	0.0%
XLg	2,029	500	500	1,029	$8.86	$24.24	$24.24	$49.89	$70.04	$13.84	$191.11	$191.11	0.0%
AnnAvg	1,145	500	500	145	$8.86	$24.24	$24.24	$7.01	$39.51	$7.81	$111.67	$111.67	0.0%
ResAvg	1,150	500	500	150	$8.86	$24.24	$24.24	$7.27	$39.70	$7.84	$112.15	$112.15	0.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.23				$17.00	$0.06116	$0.08310	$0.08310	$0.051660	$0.00000				
Off-Peak	0.77					$0.06116	$0.08310	$0.08310	$0.026750					
Small	1,376	500	500	376	$17.00	$30.58	$41.55	$31.25	$44.61	$0.00	$164.99	$149.99	$17.54	13.2%
Medium	1,897	500	500	897	$17.00	$30.58	$41.55	$74.54	$61.51	$0.00	$225.18	$210.18	$30.92	17.2%
Large	2,029	500	500	1,029	$17.00	$30.58	$41.55	$85.51	$65.79	$0.00	$240.43	$225.43	$34.32	18.0%
XLg	2,029	500	500	1,029	$17.00	$30.58	$41.55	$85.51	$65.79	$0.00	$240.43	$225.43	$34.32	18.0%
AnnAvg	1,145	500	500	145	$17.00	$30.58	$41.55	$12.01	$37.11	$0.00	$138.25	$123.25	$11.58	10.4%
ResAvg	1,150	500	500	150	$17.00	$30.58	$41.55	$12.47	$37.29	$0.00	$138.89	$123.89	$11.74	10.5%

LIFELINE SERVICE TIME OF USE RATE R-06-21 FROZEN

Winter

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.25				$8.86	$0.06520	$0.06520	$0.06520	$0.040698	$0.00682			
Off-Peak	0.75					$0.03300	$0.03300	$0.03300	$0.020698				
Small	811	500	311	0	$8.86	$20.51	$12.76	$0.00	$20.82	$5.53	$68.48	$59.48	-13.1%
Medium	1,159	500	500	159	$8.86	$20.51	$20.51	$6.52	$29.76	$7.90	$94.06	$85.06	-9.6%
Large	1,610	500	500	610	$8.86	$20.51	$20.51	$25.02	$41.34	$10.98	$127.22	$118.22	-7.1%
XLg	2,299	500	500	1,299	$8.86	$20.51	$20.51	$53.28	$59.03	$15.68	$177.87	$168.87	-5.1%
AnnAvg	1,151	500	500	151	$8.86	$20.51	$20.51	$6.21	$29.56	$7.85	$93.50	$84.50	-9.6%
ResAvg	785	500	285	0	$8.86	$20.51	$11.69	$0.00	$20.16	$5.35	$66.57	$57.57	-13.5%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.25				$17.00	$0.06116	$0.08310	$0.08310	$0.056000	$0.00000				
Off-Peak	0.75					$0.06116	$0.08310	$0.08310	$0.028092					
Small	811	500	311	0	$17.00	$30.58	$25.84	$0.00	$28.40	$0.00	$101.82	$70.82	$11.34	19.1%
Medium	1,159	500	500	159	$17.00	$30.58	$41.55	$13.21	$40.59	$0.00	$142.93	$111.93	$26.87	31.6%
Large	1,610	500	500	610	$17.00	$30.58	$41.55	$50.69	$56.39	$0.00	$196.21	$165.21	$46.99	39.7%
XLg	2,299	500	500	1,299	$17.00	$30.58	$41.55	$107.95	$80.52	$0.00	$277.60	$246.60	$77.73	46.0%
AnnAvg	1,151	500	500	151	$17.00	$30.58	$41.55	$12.57	$40.32	$0.00	$142.02	$111.02	$26.52	31.4%
ResAvg	785	500	285	0	$17.00	$30.58	$23.68	$0.00	$27.49	$0.00	$98.75	$67.75	$10.18	17.7%

LIFELINE SERVICE TIME OF USE RATE R-06-21 FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000	$8.86	500	1000	>1000					
On-Peak	0.34					$0.07880	$0.07880	$0.07880	$0.053198	$0.00682			
Off-Peak	0.66					$0.03010	$0.03010	$0.03010	$0.023198				
Small	1,065	500	500	65	$8.86	$23.29	$23.29	$3.03	$35.52	$7.26	$101.25	$92.25	-8.9%
Medium	1,606	500	500	606	$8.86	$23.29	$23.29	$28.23	$53.56	$10.95	$148.18	$139.18	-6.1%
Large	2,060	500	500	1,060	$8.86	$23.29	$23.29	$49.38	$68.70	$14.05	$187.57	$178.57	-4.8%
XLg	2,900	500	500	1,900	$8.86	$23.29	$23.29	$88.50	$96.72	$19.78	$260.44	$251.44	-3.5%
AnnAvg	1,151	500	500	151	$8.86	$23.29	$23.29	$7.05	$38.40	$7.85	$108.74	$99.74	-8.3%
ResAvg	1,150	500	500	150	$8.86	$23.29	$23.29	$6.99	$38.35	$7.84	$108.62	$99.62	-8.3%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.23				$17.00	$0.06116	$0.08310	$0.08310	$0.051660	$0.00000				
Off-Peak	0.77					$0.06116	$0.08310	$0.08310	$0.026750					
Small	1,065	500	500	65	$17.00	$30.58	$41.55	$5.40	$34.53	$0.00	$129.06	$98.06	$5.81	6.3%
Medium	1,606	500	500	606	$17.00	$30.58	$41.55	$50.36	$52.07	$0.00	$191.56	$160.56	$21.38	15.4%
Large	2,060	500	500	1,060	$17.00	$30.58	$41.55	$88.09	$66.79	$0.00	$244.01	$213.01	$34.44	19.3%
XLg	2,900	500	500	1,900	$17.00	$30.58	$41.55	$157.89	$94.03	$0.00	$341.05	$310.05	$58.61	23.3%
AnnAvg	1,151	500	500	151	$17.00	$30.58	$41.55	$12.57	$37.33	$0.00	$139.03	$108.03	$8.29	8.3%
ResAvg	1,150	500	500	150	$17.00	$30.58	$41.55	$12.47	$37.29	$0.00	$138.89	$107.89	$8.27	8.3%

LIFELINE SERVICE TIME OF USE RATE R-08-21 FROZEN

Winter

	BILL IMPACTS CURRENT RATES												
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.25				$8.86	$0.06520	$0.06520	$0.06520	$0.040698	$0.00682			
Off-Peak	0.75					$0.03300	$0.03300	$0.03300	$0.020698				
Small	1,070	500	500	70	$8.86	$20.45	$20.45	$2.86	$27.39	$7.30	$87.31	$61.12	-30.0%
Medium	1,285	500	500	285	$8.86	$20.45	$20.45	$11.66	$32.90	$8.76	$103.08	$72.16	-30.0%
Large	1,891	500	500	891	$8.86	$20.45	$20.45	$36.44	$48.41	$12.90	$147.51	$103.26	-30.0%
XLg	2,480	500	500	1,480	$8.86	$20.45	$20.45	$60.53	$63.49	$16.91	$190.69	$171.62	-10.0%
AnnAvg	1,485	500	500	485	$8.86	$20.45	$20.45	$19.85	$38.03	$10.13	$117.77	$82.44	-30.0%
ResAvg	785	500	285	0	$8.86	$20.45	$11.66	$0.00	$20.10	$5.35	$66.42	$43.17	-35.0%

	BILL IMPACTS PROPOSED RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000						
On-Peak	0.25				$17.00	$0.06116	$0.08310	$0.08310	$0.056000	$0.00000				
Off-Peak	0.75					$0.06116	$0.08310	$0.08310	$0.028092				$ Change	% Change
Small	1,070	500	500	70	$17.00	$30.58	$41.55	$5.82	$37.48	$0.00	$132.43	$92.43	$31.31	51.2%
Medium	1,285	500	500	285	$17.00	$30.58	$41.55	$23.68	$45.01	$0.00	$157.82	$117.82	$45.66	63.3%
Large	1,891	500	500	891	$17.00	$30.58	$41.55	$74.04	$66.23	$0.00	$229.40	$189.40	$86.14	83.4%
XLg	2,480	500	500	1,480	$17.00	$30.58	$41.55	$122.99	$86.86	$0.00	$298.98	$258.98	$87.36	50.9%
AnnAvg	1,485	500	500	485	$17.00	$30.58	$41.55	$40.33	$52.02	$0.00	$181.48	$141.48	$59.04	71.6%
ResAvg	785	500	285	0	$17.00	$30.58	$23.68	$0.00	$27.49	$0.00	$98.75	$58.75	$15.58	36.1%

LIFELINE SERVICE TIME OF USE RATE R-08-21 FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000	$8.86	500	1000	>1000					
On-Peak	0.36					$0.07880	$0.07880	$0.07880	$0.053198	$0.00682			
Off-Peak	0.64					$0.03010	$0.03010	$0.03010	$0.023198				
Small	1,430	500	500	430	$8.86	$23.85	$23.85	$20.51	$48.67	$9.75	$135.49	$94.84	-30.0%
Medium	2,071	500	500	1,071	$8.86	$23.85	$23.85	$51.08	$70.49	$14.12	$192.25	$173.03	-10.0%
Large	3,995	500	500	2,995	$8.86	$23.85	$23.85	$142.84	$135.97	$27.25	$362.62	$326.36	-10.0%
XLg	4,939	500	500	3,939	$8.86	$23.85	$23.85	$187.86	$168.10	$33.68	$446.20	$401.58	-10.0%
AnnAvg	1,485	500	500	485	$8.86	$23.85	$23.85	$23.14	$50.55	$10.13	$140.38	$98.27	-30.0%
ResAvg	1,150	500	500	150	$8.86	$23.85	$23.85	$7.15	$39.14	$7.84	$110.69	$77.48	-30.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.23				$17.00	$0.06116	$0.08310	$0.08310	$0.051660	$0.00000				
Off-Peak	0.77					$0.06116	$0.08310	$0.08310	$0.026750					
Small	1,430	500	500	430	$17.00	$30.58	$41.55	$35.73	$46.36	$0.00	$171.22	$131.22	$36.38	38.4%
Medium	2,071	500	500	1,071	$17.00	$30.58	$41.55	$89.00	$67.15	$0.00	$245.28	$205.28	$32.25	18.6%
Large	3,995	500	500	2,995	$17.00	$30.58	$41.55	$248.88	$129.53	$0.00	$467.54	$427.54	$101.18	31.0%
XLg	4,939	500	500	3,939	$17.00	$30.58	$41.55	$327.33	$160.14	$0.00	$576.60	$536.60	$135.02	33.6%
AnnAvg	1,485	500	500	485	$17.00	$30.58	$41.55	$40.33	$48.16	$0.00	$177.62	$137.62	$39.35	40.0%
ResAvg	1,150	500	500	150	$17.00	$30.58	$41.55	$12.47	$37.29	$0.00	$138.89	$98.89	$21.41	27.6%

LIFELINE SERVICE TIME OF USE RATE R-04-70 FROZEN

Winter

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.23				$8.78	$0.09250	$0.09250	$0.09250	$0.040698	$0.00682			
Shoulder-Peak	n/a												
Off-Peak	0.77					$0.02490	$0.02490	$0.02490	$0.020698				
Small	538	500	38	0	$8.78	$20.12	$1.51	$0.00	$13.57	$3.67	$47.65	$33.36	-30.0%
Medium	850	500	350	0	$8.78	$20.12	$14.09	$0.00	$21.45	$5.80	$70.24	$52.68	-25.0%
Large	1,402	500	500	402	$8.78	$20.12	$20.12	$16.18	$35.38	$9.56	$110.14	$93.62	-15.0%
XLg	1,734	500	500	734	$8.78	$20.12	$20.12	$29.54	$43.76	$11.83	$134.15	$134.15	0.0%
AnnAvg	831	500	331	0	$8.78	$20.12	$13.34	$0.00	$20.98	$5.67	$68.89	$51.67	-25.0%
ResAvg	785	500	285	0	$8.78	$20.12	$11.47	$0.00	$19.81	$5.35	$65.53	$49.15	-25.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.25				$17.00	$0.06116	$0.08310	$0.08310	$0.056000	$0.00000				
Off-Peak	0.75					$0.06116	$0.08310	$0.08310	$0.028092					
Small	538	500	38	0	$17.00	$30.58	$3.12	$0.00	$18.83	$0.00	$69.53	$38.53	$5.17	15.5%
Medium	850	500	350	0	$17.00	$30.58	$29.09	$0.00	$29.77	$0.00	$106.44	$75.44	$22.76	43.2%
Large	1,402	500	500	402	$17.00	$30.58	$41.55	$33.41	$49.10	$0.00	$171.64	$140.64	$47.02	50.2%
XLg	1,734	500	500	734	$17.00	$30.58	$41.55	$61.00	$60.73	$0.00	$210.86	$179.86	$45.71	34.1%
AnnAvg	831	500	331	0	$17.00	$30.58	$27.54	$0.00	$29.12	$0.00	$104.24	$73.24	$21.57	41.7%
ResAvg	785	500	285	0	$17.00	$30.58	$23.68	$0.00	$27.49	$0.00	$98.75	$67.75	$18.60	37.8%

LIFELINE SERVICE TIME OF USE RATE R-04-70 FROZEN

Summer

	BILL IMPACTS CURRENT RATES												
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.22				$8.78	$0.13930	$0.13930	$0.13930	$0.055698	$0.00682			
Shoulder-Peak	0.07					$0.07400	$0.07400	$0.07400	$0.048198				
Off-Peak	0.71					$0.03790	$0.03790	$0.03790	$0.023198				
Small	866	500	366	0	$8.78	$31.40	$22.95	$0.00	$27.85	$5.90	$96.88	$72.66	-25.0%
Medium	1,170	500	500	170	$8.78	$31.40	$31.40	$10.68	$37.64	$7.98	$127.88	$108.70	-15.0%
Large	1,910	500	500	910	$8.78	$31.40	$31.40	$57.15	$61.45	$13.03	$203.21	$203.21	0.0%
XLg	2,469	500	500	1,469	$8.78	$31.40	$31.40	$92.25	$79.43	$16.84	$260.10	$260.10	0.0%
AnnAvg	831	500	331	0	$8.78	$31.40	$20.81	$0.00	$26.75	$5.67	$93.41	$70.06	-25.0%
ResAvg	1,150	500	500	150	$8.78	$31.40	$31.40	$9.42	$37.00	$7.84	$125.84	$106.96	-15.0%

	BILL IMPACTS PROPOSED RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000						
On-Peak	0.23				$17.00	$0.06116	$0.08310	$0.08310	$0.051660	$0.00000				
Off-Peak	0.77					$0.06116	$0.08310	$0.08310	$0.026750				$ Change	% Change
Small	866	500	366	0	$17.00	$30.58	$30.37	$0.00	$28.06	$0.00	$106.01	$75.01	$2.35	3.2%
Medium	1,170	500	500	170	$17.00	$30.58	$41.55	$14.13	$37.93	$0.00	$141.19	$110.19	$1.49	1.4%
Large	1,910	500	500	910	$17.00	$30.58	$41.55	$75.62	$61.93	$0.00	$226.68	$195.68	-$7.53	-3.7%
XLg	2,469	500	500	1,469	$17.00	$30.58	$41.55	$122.07	$80.05	$0.00	$291.25	$260.25	$0.15	0.1%
AnnAvg	831	500	331	0	$17.00	$30.58	$27.54	$0.00	$26.96	$0.00	$102.08	$71.08	$1.02	1.5%
ResAvg	1,150	500	500	150	$17.00	$30.58	$41.55	$12.47	$37.29	$0.00	$138.89	$107.89	$0.93	0.9%

LIFELINE SERVICE TIME OF USE RATE R-05-70 FROZEN

Winter

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.20				$8.78	$0.09250	$0.09250	$0.09250	$0.040698	$0.00682			
Shoulder-Peak	n/a												
Off-Peak	0.80					$0.02490	$0.02490	$0.02490	$0.020698				
Small	428	428	0	0	$8.78	$16.49	$0.00	$0.00	$10.58	$2.92	$38.77	$31.02	-20.0%
Medium	776	500	276	0	$8.78	$19.26	$10.63	$0.00	$19.19	$5.29	$63.15	$53.68	-15.0%
Large	1,220	500	500	220	$8.78	$19.26	$19.26	$8.48	$30.17	$8.32	$94.27	$94.27	0.0%
XLg	1,267	500	500	267	$8.78	$19.26	$19.26	$10.29	$31.33	$8.64	$97.56	$97.56	0.0%
AnnAvg	684	500	184	0	$8.78	$19.26	$7.09	$0.00	$16.91	$4.66	$56.70	$48.20	-15.0%
ResAvg	785	500	285	0	$8.78	$19.26	$10.98	$0.00	$19.41	$5.35	$63.78	$54.21	-15.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000						
On-Peak	0.25				$17.00	$0.06116	$0.08310	$0.08310	$0.056000	$0.00000				
Off-Peak	0.75					$0.06116	$0.08310	$0.08310	$0.028092				$ Change	% Change
Small	428	428	0	0	$17.00	$26.18	$0.00	$0.00	$14.99	$0.00	$58.17	$43.17	$12.15	39.2%
Medium	776	500	276	0	$17.00	$30.58	$22.94	$0.00	$27.18	$0.00	$97.70	$82.70	$29.02	54.1%
Large	1,220	500	500	220	$17.00	$30.58	$41.55	$18.28	$42.73	$0.00	$150.14	$135.14	$40.87	43.4%
XLg	1,267	500	500	267	$17.00	$30.58	$41.55	$22.19	$44.38	$0.00	$155.70	$140.70	$43.14	44.2%
AnnAvg	684	500	184	0	$17.00	$30.58	$15.28	$0.00	$23.95	$0.00	$86.81	$71.81	$23.61	49.0%
ResAvg	785	500	285	0	$17.00	$30.58	$23.68	$0.00	$27.49	$0.00	$98.75	$83.75	$29.54	54.5%

LIFELINE SERVICE TIME OF USE RATE R-05-70 FROZEN

Summer

	BILL IMPACTS CURRENT RATES												
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.20				$8.78	$0.13930	$0.13930	$0.13930	$0.055698	$0.00682			
Shoulder-Pea	0.08					$0.07400	$0.07400	$0.07400	$0.048198				
Off-Peak	0.72					$0.03790	$0.03790	$0.03790	$0.023198				
Small	752	500	252	0	$8.78	$30.66	$15.42	$0.00	$23.88	$5.13	$83.87	$71.29	-15.0%
Medium	1,203	500	500	203	$8.78	$30.66	$30.66	$12.42	$38.22	$8.20	$128.94	$128.94	0.0%
Large	1,647	500	500	647	$8.78	$30.66	$30.66	$39.68	$52.35	$11.23	$173.36	$173.36	0.0%
XLg	1,935	500	500	935	$8.78	$30.66	$30.66	$57.34	$61.50	$13.20	$202.14	$202.14	0.0%
AnnAvg	684	500	184	0	$8.78	$30.66	$11.28	$0.00	$21.74	$4.66	$77.12	$65.55	-15.0%
ResAvg	1,150	500	500	150	$8.78	$30.66	$30.66	$9.20	$36.55	$7.84	$123.69	$123.69	0.0%

	BILL IMPACTS PROPOSED RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000						
On-Peak	0.23				$17.00	$0.06116	$0.08310	$0.08310	$0.051660	$0.00000				
Off-Peak	0.77					$0.06116	$0.08310	$0.08310	$0.026750				$ Change	% Change
Small	752	500	252	0	$17.00	$30.58	$20.90	$0.00	$24.37	$0.00	$92.85	$77.85	$6.56	9.2%
Medium	1,203	500	500	203	$17.00	$30.58	$41.55	$16.83	$38.99	$0.00	$144.95	$129.95	$1.01	0.8%
Large	1,647	500	500	647	$17.00	$30.58	$41.55	$53.77	$53.40	$0.00	$196.30	$181.30	$7.94	4.6%
XLg	1,935	500	500	935	$17.00	$30.58	$41.55	$77.70	$62.74	$0.00	$229.57	$214.57	$12.43	6.1%
AnnAvg	684	500	184	0	$17.00	$30.58	$15.28	$0.00	$22.17	$0.00	$85.03	$70.03	$4.48	6.8%
ResAvg	1,150	500	500	150	$17.00	$30.58	$41.55	$12.47	$37.29	$0.00	$138.89	$123.89	$0.20	0.2%

LIFELINE SERVICE TIME OF USE RATE R-06-70 FROZEN

Winter

	BILL IMPACTS CURRENT RATES												
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.23				$8.78	$0.09250	$0.09250	$0.09250	$0.040698	$0.00682			
Shoulder-Peak	n/a												
Off-Peak	0.77					$0.02490	$0.02490	$0.02490	$0.020698				
Small	664	500	164	0	$8.78	$20.14	$6.60	$0.00	$16.76	$4.53	$56.81	$47.81	-15.8%
Medium	1,011	500	500	11	$8.78	$20.14	$20.14	$0.44	$25.52	$6.90	$81.92	$72.92	-11.0%
Large	1,395	500	500	395	$8.78	$20.14	$20.14	$15.91	$35.22	$9.51	$109.70	$100.70	-8.2%
XLg	1,744	500	500	744	$8.78	$20.14	$20.14	$29.96	$44.03	$11.89	$134.94	$125.94	-6.7%
AnnAvg	933	500	433	0	$8.78	$20.14	$17.43	$0.00	$23.55	$6.36	$76.26	$67.26	-11.8%
ResAvg	785	500	285	0	$8.78	$20.14	$11.48	$0.00	$19.82	$5.35	$65.57	$56.57	-13.7%

	BILL IMPACTS PROPOSED RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000						
On-Peak	0.25				$17.00	$0.06116	$0.08310	$0.08310	$0.056000	$0.00000				
Off-Peak	0.75					$0.06116	$0.08310	$0.08310	$0.028092				$ Change	% Change
Small	664	500	164	0	$17.00	$30.58	$13.63	$0.00	$23.26	$0.00	$84.47	$69.47	$21.66	45.3%
Medium	1,011	500	500	11	$17.00	$30.58	$41.55	$0.91	$35.41	$0.00	$125.45	$110.45	$37.53	51.5%
Large	1,395	500	500	395	$17.00	$30.58	$41.55	$32.82	$48.86	$0.00	$170.81	$155.81	$55.11	54.7%
XLg	1,744	500	500	744	$17.00	$30.58	$41.55	$61.83	$61.08	$0.00	$212.04	$197.04	$71.10	56.5%
AnnAvg	933	500	433	0	$17.00	$30.58	$35.97	$0.00	$32.67	$0.00	$116.22	$101.22	$33.96	50.5%
ResAvg	785	500	285	0	$17.00	$30.58	$23.68	$0.00	$27.49	$0.00	$98.75	$83.75	$27.18	48.0%

LIFELINE SERVICE TIME OF USE RATE R-06-70 FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.20				$8.78	$0.13930	$0.13930	$0.13930	$0.055698	$0.00682			
Shoulder-Pea	0.09					$0.07400	$0.07400	$0.07400	$0.048198				
Off-Peak	0.71					$0.03790	$0.03790	$0.03790	$0.023198				
Small	971	500	471	0	$8.78	$30.93	$29.10	$0.00	$31.12	$6.62	$106.55	$97.55	-8.4%
Medium	1,577	500	500	577	$8.78	$30.93	$30.93	$35.69	$50.57	$10.76	$167.66	$158.66	-5.4%
Large	2,196	500	500	1,196	$8.78	$30.93	$30.93	$73.97	$70.42	$14.98	$230.01	$221.01	-3.9%
XLg	2,503	500	500	1,503	$8.78	$30.93	$30.93	$92.96	$80.27	$17.07	$260.94	$251.94	-3.4%
AnnAvg	933	500	433	0	$8.78	$30.93	$26.77	$0.00	$29.92	$6.36	$102.76	$93.76	-8.8%
ResAvg	1,150	500	500	150	$8.78	$30.93	$30.93	$9.28	$36.88	$7.84	$124.64	$115.64	-7.2%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000						
On-Peak	0.23				$17.00	$0.06116	$0.08310	$0.08310	$0.051660	$0.00000				
Off-Peak	0.77					$0.06116	$0.08310	$0.08310	$0.026750				$ Change	% Change
Small	971	500	471	0	$17.00	$30.58	$39.10	$0.00	$31.47	$0.00	$118.15	$103.15	$5.60	5.7%
Medium	1,577	500	500	577	$17.00	$30.58	$41.55	$47.95	$51.13	$0.00	$188.21	$173.21	$14.55	9.2%
Large	2,196	500	500	1,196	$17.00	$30.58	$41.55	$99.39	$71.20	$0.00	$259.72	$244.72	$23.71	10.7%
XLg	2,503	500	500	1,503	$17.00	$30.58	$41.55	$124.90	$81.15	$0.00	$295.18	$280.18	$28.24	11.2%
AnnAvg	933	500	433	0	$17.00	$30.58	$35.97	$0.00	$30.24	$0.00	$113.79	$98.79	$5.03	5.4%
ResAvg	1,150	500	500	150	$17.00	$30.58	$41.55	$12.47	$37.29	$0.00	$138.89	$123.89	$8.25	7.1%

LIFELINE SERVICE TIME OF USE RATE R-08-70 FROZEN

Winter

	BILL IMPACTS CURRENT RATES												
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.22				$8.78	$0.09250	$0.09250	$0.09250	$0.040698	$0.00682			
Shoulder-Peak	n/a												
Off-Peak	0.78					$0.02490	$0.02490	$0.02490	$0.020698				
Small	770	500	270	0	$8.78	$19.74	$10.66	$0.00	$19.26	$5.25	$63.69	$41.40	-35.0%
Medium	980	500	480	0	$8.78	$19.74	$18.95	$0.00	$24.51	$6.68	$78.66	$51.13	-35.0%
Large	1,312	500	500	312	$8.78	$19.74	$19.74	$12.32	$32.81	$8.95	$102.34	$71.64	-30.0%
XLg	1,636	500	500	636	$8.78	$19.74	$19.74	$25.11	$40.92	$11.16	$125.45	$87.82	-30.0%
AnnAvg	994	500	494	0	$8.78	$19.74	$19.49	$0.00	$24.85	$6.78	$79.64	$51.77	-35.0%
ResAvg	785	500	285	0	$8.78	$19.74	$11.25	$0.00	$19.63	$5.35	$64.75	$42.09	-35.0%

	BILL IMPACTS PROPOSED RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000						
On-Peak	0.25				$17.00	$0.06116	$0.08310	$0.08310	$0.056000	$0.00000				
Off-Peak	0.75					$0.06116	$0.08310	$0.08310	$0.028092				$ Change	% Change
Small	770	500	270	0	$17.00	$30.58	$22.44	$0.00	$26.97	$0.00	$96.99	$56.99	$15.59	37.7%
Medium	980	500	480	0	$17.00	$30.58	$39.89	$0.00	$34.32	$0.00	$121.79	$81.79	$30.66	60.0%
Large	1,312	500	500	312	$17.00	$30.58	$41.55	$25.93	$45.95	$0.00	$161.01	$121.01	$49.37	68.9%
XLg	1,636	500	500	636	$17.00	$30.58	$41.55	$52.85	$57.30	$0.00	$199.28	$159.28	$71.46	81.4%
AnnAvg	994	500	494	0	$17.00	$30.58	$41.03	$0.00	$34.80	$0.00	$123.41	$83.41	$31.64	61.1%
ResAvg	785	500	285	0	$17.00	$30.58	$23.68	$0.00	$27.49	$0.00	$98.75	$58.75	$16.66	39.6%

LIFELINE SERVICE TIME OF USE RATE R-08-70 FROZEN

Summer

	BILL IMPACTS CURRENT RATES												
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.20				$8.78	$0.13930	$0.13930	$0.13930	$0.055698	$0.00682			
Shoulder-Pea	0.08					$0.07400	$0.07400	$0.07400	$0.048198				
Off-Peak	0.72					$0.03790	$0.03790	$0.03790	$0.023198				
Small	1,206	500	500	206	$8.78	$30.44	$30.44	$12.51	$38.18	$8.22	$128.57	$90.00	-30.0%
Medium	1,820	500	500	820	$8.78	$30.44	$30.44	$49.93	$57.65	$12.41	$189.65	$132.76	-30.0%
Large	2,139	500	500	1,139	$8.78	$30.44	$30.44	$69.35	$67.75	$14.59	$221.35	$199.22	-10.0%
XLg	2,382	500	500	1,382	$8.78	$30.44	$30.44	$84.14	$75.45	$16.25	$245.50	$220.95	-10.0%
AnnAvg	994	500	494	0	$8.78	$30.44	$30.06	$0.00	$31.48	$6.78	$107.54	$69.90	-35.0%
ResAvg	1,150	500	500	150	$8.78	$30.44	$30.44	$9.13	$36.43	$7.84	$123.06	$86.14	-30.0%

	BILL IMPACTS PROPOSED RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000						
On-Peak	0.23				$17.00	$0.06116	$0.08310	$0.08310	$0.051660	$0.00000				
Off-Peak	0.77					$0.06116	$0.08310	$0.08310	$0.026750				$ Change	% Change
Small	1,206	500	500	206	$17.00	$30.58	$41.55	$17.08	$39.09	$0.00	$145.30	$105.30	$15.30	17.0%
Medium	1,820	500	500	820	$17.00	$30.58	$41.55	$68.14	$59.01	$0.00	$216.28	$176.28	$43.52	32.8%
Large	2,139	500	500	1,139	$17.00	$30.58	$41.55	$94.65	$69.35	$0.00	$253.13	$213.13	$13.91	7.0%
XLg	2,382	500	500	1,382	$17.00	$30.58	$41.55	$114.84	$77.23	$0.00	$281.20	$241.20	$20.25	9.2%
AnnAvg	994	500	494	0	$17.00	$30.58	$41.03	$0.00	$32.22	$0.00	$120.83	$80.83	$10.93	15.6%
ResAvg	1,150	500	500	150	$17.00	$30.58	$41.55	$12.47	$37.29	$0.00	$138.89	$98.89	$12.75	14.8%

RESIDENTIAL SERVICE TIME OF USE SUPER-PEAK RATE R-8

Winter

	BILL IMPACTS CURRENT RATES										
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill
		500	1000	>1000		500	1000	>1000			
On-Peak	0.11				$11.50	$0.08910	$0.08910	$0.11210	$0.040200	$0.00682	
Off-Peak	0.89					$0.03850	$0.03850	$0.06150	$0.020500		
Small	557	500	57	0	$11.50	$22.05	$2.51	$0.00	$12.63	$3.80	$52.49
Medium	876	500	376	0	$11.50	$22.05	$16.56	$0.00	$19.85	$5.97	$75.93
Large	1,370	500	500	370	$11.50	$22.05	$22.05	$24.82	$31.07	$9.34	$120.83
XLg	1,715	500	500	715	$11.50	$22.05	$22.05	$47.97	$38.89	$11.70	$154.16
AnnAvg	769	500	269	0	$11.50	$22.05	$11.86	$0.00	$17.44	$5.24	$68.09
ResAvg	785	500	285	0	$11.50	$22.05	$12.57	$0.00	$17.80	$5.35	$69.27

	BILL IMPACTS PROPOSED RATES												
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill		
		500	1000	>1000		500	1000	>1000					
On-Peak	0.11				$17.00	$0.06116	$0.08310	$0.08310	$0.041293	$0.00000			
Off-Peak	0.89					$0.06116	$0.08310	$0.08310	$0.021492			$ Change	% Change
Small	557	500	57	0	$17.00	$30.58	$4.74	$0.00	$13.19	$0.00	$65.51	$13.02	24.8%
Medium	876	500	376	0	$17.00	$30.58	$31.20	$0.00	$20.73	$0.00	$99.51	$23.58	31.1%
Large	1,370	500	500	370	$17.00	$30.58	$41.55	$30.75	$32.44	$0.00	$152.32	$31.49	26.1%
XLg	1,715	500	500	715	$17.00	$30.58	$41.55	$59.42	$40.61	$0.00	$189.16	$35.00	22.7%
AnnAvg	769	500	269	0	$17.00	$30.58	$22.34	$0.00	$18.21	$0.00	$88.13	$20.04	29.4%
ResAvg	785	500	285	0	$17.00	$30.58	$23.68	$0.00	$18.59	$0.00	$89.85	$20.58	29.7%

RESIDENTIAL SERVICE TIME OF USE SUPER-PEAK RATE R-8

Summer

	BILL IMPACTS CURRENT RATES										
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill
		500	1000	>1000	$11.50	500	1000	>1000			
On-Peak	0.13					$0.09710	$0.09710	$0.12010	$0.080100	$0.00682	
Off-Peak	0.87					$0.04850	$0.04850	$0.07150	$0.022200		
Small	728	500	228	0	$11.50	$27.39	$12.46	$0.00	$21.59	$4.96	$77.90
Medium	1,222	500	500	222	$11.50	$27.39	$27.39	$17.27	$36.26	$8.33	$128.14
Large	1,666	500	500	666	$11.50	$27.39	$27.39	$51.80	$49.44	$11.36	$178.88
XLg	2,219	500	500	1,219	$11.50	$27.39	$27.39	$94.81	$65.85	$15.13	$242.07
AnnAvg	769	500	269	0	$11.50	$27.39	$14.73	$0.00	$22.82	$5.24	$81.68
ResAvg	1,150	500	500	150	$11.50	$27.39	$27.39	$11.67	$34.13	$7.84	$119.92

	BILL IMPACTS PROPOSED RATES												
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill		
		500	1000	>1000		500	1000	>1000					
On-Peak	0.13				$17.00	$0.06116	$0.08310	$0.08310	$0.081060	$0.00000			
Off-Peak	0.87					$0.06116	$0.08310	$0.08310	$0.022750			$ Change	% Change
Small	728	500	228	0	$17.00	$30.58	$18.91	$0.00	$22.03	$0.00	$88.52	$10.62	13.6%
Medium	1,222	500	500	222	$17.00	$30.58	$41.55	$18.45	$37.00	$0.00	$144.58	$16.44	12.8%
Large	1,666	500	500	666	$17.00	$30.58	$41.55	$55.34	$50.44	$0.00	$194.91	$16.03	9.0%
XLg	2,219	500	500	1,219	$17.00	$30.58	$41.55	$101.30	$67.19	$0.00	$257.62	$15.55	6.4%
AnnAvg	769	500	269	0	$17.00	$30.58	$22.34	$0.00	$23.28	$0.00	$93.20	$11.52	14.1%
ResAvg	1,150	500	500	150	$17.00	$30.58	$41.55	$12.47	$34.82	$0.00	$136.42	$16.50	13.8%

LIFELINE RESIDENTIAL SERVICE TIME OF USE SUPER-PEAK RATE R-8L

Winter

	BILL IMPACTS CURRENT RATES												
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.11				$11.50	$0.08910	$0.08910	$0.11210	$0.040200	$0.00682			
Off-Peak	0.89					$0.03850	$0.03850	$0.06150	$0.020500				
Small	461	461	0	0	$11.50	$20.33	$0.00	$0.00	$10.45	$3.14	$45.42	$36.42	-19.8%
Medium	835	500	335	0	$11.50	$22.05	$14.77	$0.00	$18.94	$5.69	$72.95	$63.95	-12.3%
Large	946	500	446	0	$11.50	$22.05	$19.66	$0.00	$21.45	$6.45	$81.11	$72.11	-11.1%
XLg	980	500	480	0	$11.50	$22.05	$21.16	$0.00	$22.22	$6.68	$83.61	$74.61	-10.8%
AnnAvg	729	500	229	0	$11.50	$22.05	$10.11	$0.00	$16.54	$4.97	$65.17	$56.17	-13.8%
ResAvg	785	500	285	0	$11.50	$22.05	$12.57	$0.00	$17.80	$5.35	$69.27	$60.27	-13.0%

	BILL IMPACTS PROPOSED RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000						
On-Peak	0.11				$17.00	$0.06116	$0.08310	$0.08310	$0.041293	$0.00000				
Off-Peak	0.89					$0.06116	$0.08310	$0.08310	$0.021492				$ Change	% Change
Small	461	461	0	0	$17.00	$28.19	$0.00	$0.00	$10.92	$0.00	$56.11	$41.11	$4.69	12.9%
Medium	835	500	335	0	$17.00	$30.58	$27.84	$0.00	$19.77	$0.00	$95.19	$80.19	$16.24	25.4%
Large	946	500	446	0	$17.00	$30.58	$37.06	$0.00	$22.40	$0.00	$107.04	$92.04	$19.93	27.6%
XLg	980	500	480	0	$17.00	$30.58	$39.89	$0.00	$23.21	$0.00	$110.68	$95.68	$21.07	28.2%
AnnAvg	729	500	229	0	$17.00	$30.58	$19.06	$0.00	$17.27	$0.00	$83.91	$68.91	$12.74	22.7%
ResAvg	785	500	285	0	$17.00	$30.58	$23.68	$0.00	$18.59	$0.00	$89.85	$74.85	$14.58	24.2%

LIFELINE RESIDENTIAL SERVICE TIME OF USE SUPER-PEAK RATE R-8L

Summer

	BILL IMPACTS CURRENT RATES												
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000	$11.50	500	1000	>1000					
On-Peak	0.13					$0.09710	$0.09710	$0.12010	$0.080100	$0.00682			
Off-Peak	0.87					$0.04850	$0.04850	$0.07150	$0.022200				
Small	1,305	500	500	305	$11.50	$27.39	$27.39	$23.72	$38.73	$8.90	$137.63	$128.63	-6.5%
Medium	1,464	500	500	464	$11.50	$27.39	$27.39	$36.09	$43.44	$9.98	$155.79	$146.79	-5.8%
Large	1,559	500	500	559	$11.50	$27.39	$27.39	$43.48	$46.26	$10.63	$166.65	$157.65	-5.4%
XLg	1,559	500	500	559	$11.50	$27.39	$27.39	$43.48	$46.26	$10.63	$166.65	$157.65	-5.4%
AnnAvg	729	500	229	0	$11.50	$27.39	$12.56	$0.00	$21.64	$4.97	$78.06	$69.06	-11.5%
ResAvg	1,150	500	500	150	$11.50	$27.39	$27.39	$11.67	$34.13	$7.84	$119.92	$110.92	-7.5%

	BILL IMPACTS PROPOSED RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000						
On-Peak	0.13				$17.00	$0.06116	$0.08310	$0.08310	$0.081060	$0.00000				
Off-Peak	0.87					$0.06116	$0.08310	$0.08310	$0.022750				$ Change	% Change
Small	1,305	500	500	305	$17.00	$30.58	$41.55	$25.35	$39.51	$0.00	$153.99	$138.99	$10.36	8.1%
Medium	1,464	500	500	464	$17.00	$30.58	$41.55	$38.56	$44.33	$0.00	$172.02	$157.02	$10.23	7.0%
Large	1,559	500	500	559	$17.00	$30.58	$41.55	$46.45	$47.20	$0.00	$182.78	$167.78	$10.13	6.4%
XLg	1,559	500	500	559	$17.00	$30.58	$41.55	$46.45	$47.20	$0.00	$182.78	$167.78	$10.13	6.4%
AnnAvg	729	500	229	0	$17.00	$30.58	$19.06	$0.00	$22.08	$0.00	$88.72	$73.72	$4.66	6.7%
ResAvg	1,150	500	500	150	$17.00	$30.58	$41.55	$12.47	$34.82	$0.00	$136.42	$121.42	$10.50	9.5%

SPECIAL RESIDENTIAL ELECTRIC SERVICE RATE R-201A

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill
		500	1000	3500	>3500		500	1000	3500	>3500			
						$10.00	$0.05060	$0.05870	$0.07030	$0.07840	$0.031532	$0.00682	
Small	759	500	259	0	0	$10.00	$25.30	$15.20	$0.00	$0.00	$23.93	$5.18	$79.61
Medium	1,110	500	500	110	0	$10.00	$25.30	$29.35	$7.73	$0.00	$35.00	$7.57	$114.95
Large	1,513	500	500	513	0	$10.00	$25.30	$29.35	$36.06	$0.00	$47.71	$10.32	$158.74
XLg	1,820	500	500	820	0	$10.00	$25.30	$29.35	$57.65	$0.00	$57.39	$12.41	$192.10
AnnAvg	946	500	446	0	0	$10.00	$25.30	$26.17	$0.00	$0.00	$29.82	$6.45	$97.74
ResAvg	785	500	285	0	0	$10.00	$25.30	$16.73	$0.00	$0.00	$24.75	$5.35	$82.13

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill		
		500	1000	>1000			500	1000	>1000						
						$17.00	$0.06116	$0.08310	$0.08310		$0.026030	$0.00000			
														$ Change	% Change
Small	759	500	259	0		$17.00	$30.58	$21.52	$0.00		$19.76	$0.00	$88.86	$9.25	11.6%
Medium	1,110	500	500	110		$17.00	$30.58	$41.55	$9.14		$28.89	$0.00	$127.16	$12.21	10.6%
Large	1,513	500	500	513		$17.00	$30.58	$41.55	$42.63		$39.38	$0.00	$171.14	$12.40	7.8%
XLg	1,820	500	500	820		$17.00	$30.58	$41.55	$68.14		$47.37	$0.00	$204.64	$12.54	6.5%
AnnAvg	946	500	446	0		$17.00	$30.58	$37.04	$0.00		$24.62	$0.00	$109.24	$11.50	11.8%
ResAvg	785	500	285	0		$17.00	$30.58	$23.68	$0.00		$20.43	$0.00	$91.69	$9.56	11.6%

SPECIAL RESIDENTIAL ELECTRIC SERVICE RATE R-201A

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill
		500	1000	3500	>3500		500	1000	3500	>3500			
						$10.00	$0.05060	$0.06050	$0.07180	$0.07940	$0.035111	$0.00682	
Small	1,017	500	500	17	0	$10.00	$25.30	$30.25	$1.22	$0.00	$35.71	$6.94	$109.42
Medium	1,505	500	500	505	0	$10.00	$25.30	$30.25	$36.26	$0.00	$52.84	$10.26	$164.91
Large	1,999	500	500	999	0	$10.00	$25.30	$30.25	$71.73	$0.00	$70.19	$13.63	$221.10
XLg	2,349	500	500	1,349	0	$10.00	$25.30	$30.25	$96.86	$0.00	$82.48	$16.02	$260.91
AnnAvg	946	500	446	0	0	$10.00	$25.30	$26.97	$0.00	$0.00	$33.21	$6.45	$101.93
ResAvg	1,150	500	500	150	0	$10.00	$25.30	$30.25	$10.77	$0.00	$40.38	$7.84	$124.54

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	$ Change	% Change
		500	1000	>1000			500	1000	>1000						
						$17.00	$0.06116	$0.08310	$0.08310		$0.028694	$0.00000			
Small	1,017	500	500	17		$17.00	$30.58	$41.55	$1.41		$29.18	$0.00	$119.72	$10.30	9.4%
Medium	1,505	500	500	505		$17.00	$30.58	$41.55	$41.97		$43.18	$0.00	$174.28	$9.37	5.7%
Large	1,999	500	500	999		$17.00	$30.58	$41.55	$83.02		$57.36	$0.00	$229.51	$8.41	3.8%
XLg	2,349	500	500	1,349		$17.00	$30.58	$41.55	$112.10		$67.40	$0.00	$268.63	$7.72	3.0%
AnnAvg	946	500	446	0		$17.00	$30.58	$37.04	$0.00		$27.14	$0.00	$111.76	$9.83	9.6%
ResAvg	1,150	500	500	150		$17.00	$30.58	$41.55	$12.47		$33.00	$0.00	$134.60	$10.06	8.1%

SPECIAL LIFELINE RESIDENTIAL ELECTRIC SERVICE RATE R-201A

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	3500	>3500		500	1000	3500	>3500					
						$10.00	$0.05060	$0.05870	$0.07030	$0.07840	$0.031532	$0.00682			
Small	691	500	191	0	0	$10.00	$25.30	$11.18	$0.00	$0.00	$21.77	$4.71	$72.96	$63.96	-12.3%
Medium	1,009	500	500	9	0	$10.00	$25.30	$29.35	$0.63	$0.00	$31.82	$6.88	$103.98	$94.98	-8.7%
Large	1,342	500	500	342	0	$10.00	$25.30	$29.35	$24.04	$0.00	$42.32	$9.15	$140.16	$131.16	-6.4%
XLg	1,581	500	500	581	0	$10.00	$25.30	$29.35	$40.84	$0.00	$49.85	$10.78	$166.12	$157.12	-5.4%
AnnAvg	862	500	362	0	0	$10.00	$25.30	$21.24	$0.00	$0.00	$27.17	$5.88	$89.59	$80.59	-10.0%
ResAvg	785	500	285	0	0	$10.00	$25.30	$16.73	$0.00	$0.00	$24.75	$5.35	$82.13	$73.13	-11.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000			500	1000	>1000							
						$17.00	$0.06116	$0.08310	$0.08310		$0.026030	$0.00000				
Small	691	500	191	0		$17.00	$30.58	$15.83	$0.00		$17.97	$0.00	$81.38	$66.38	$2.42	3.8%
Medium	1,009	500	500	9		$17.00	$30.58	$41.55	$0.75		$26.26	$0.00	$116.14	$101.14	$6.16	6.5%
Large	1,342	500	500	342		$17.00	$30.58	$41.55	$28.42		$34.93	$0.00	$152.48	$137.48	$6.32	4.8%
XLg	1,581	500	500	581		$17.00	$30.58	$41.55	$48.28		$41.15	$0.00	$178.56	$163.56	$6.44	4.1%
AnnAvg	862	500	362	0		$17.00	$30.58	$30.07	$0.00		$22.43	$0.00	$100.08	$85.08	$4.49	5.6%
ResAvg	785	500	285	0		$17.00	$30.58	$23.68	$0.00		$20.43	$0.00	$91.69	$76.69	$3.56	4.9%

SPECIAL LIFELINE RESIDENTIAL ELECTRIC SERVICE RATE R-201A

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	3500	>3500		500	1000	3500	>3500					
						$10.00	$0.05060	$0.06050	$0.07180	$0.07940	$0.035111	$0.00682			
Small	877	500	377	0	0	$10.00	$25.30	$22.81	$0.00	$0.00	$30.79	$5.98	$94.88	$85.88	-9.5%
Medium	1,268	500	500	268	0	$10.00	$25.30	$30.25	$19.24	$0.00	$44.52	$8.65	$137.96	$128.96	-6.5%
Large	1,815	500	500	815	0	$10.00	$25.30	$30.25	$58.52	$0.00	$63.73	$12.38	$200.18	$191.18	-4.5%
XLg	2,060	500	500	1,060	0	$10.00	$25.30	$30.25	$76.11	$0.00	$72.33	$14.05	$228.04	$219.04	-3.9%
AnnAvg	862	500	362	0	0	$10.00	$25.30	$21.89	$0.00	$0.00	$30.26	$5.88	$93.33	$84.33	-9.6%
ResAvg	1,150	500	500	150	0	$10.00	$25.30	$30.25	$10.77	$0.00	$40.38	$7.84	$124.54	$115.54	-7.2%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000			500	1000	>1000							
						$17.00	$0.06116	$0.08310	$0.08310		$0.028694	$0.00000				
Small	877	500	377	0		$17.00	$30.58	$31.33	$0.00		$25.16	$0.00	$104.07	$89.07	$3.19	3.7%
Medium	1,268	500	500	268		$17.00	$30.58	$41.55	$22.27		$36.38	$0.00	$147.78	$132.78	$3.82	3.0%
Large	1,815	500	500	815		$17.00	$30.58	$41.55	$67.73		$52.08	$0.00	$208.94	$193.94	$2.76	1.4%
XLg	2,060	500	500	1,060		$17.00	$30.58	$41.55	$88.09		$59.11	$0.00	$236.33	$221.33	$2.29	1.0%
AnnAvg	862	500	362	0		$17.00	$30.58	$30.07	$0.00		$24.73	$0.00	$102.38	$87.38	$3.05	3.6%
ResAvg	1,150	500	500	150		$17.00	$30.58	$41.55	$12.47		$33.00	$0.00	$134.60	$119.60	$4.06	3.5%

SPECIAL LIFELINE RESIDENTIAL ELECTRIC SERVICE RATE R-06-201AF FROZEN

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
					$6.90	$0.04130	$0.04130	$0.04130	$0.027198	$0.00682			
Small	694	500	194	0	$6.90	$20.65	$7.99	$0.00	$18.86	$4.73	$59.13	$50.13	-15.2%
Medium	1,030	500	500	30	$6.90	$20.65	$20.65	$1.24	$28.01	$7.02	$84.47	$75.47	-10.7%
Large	1,310	500	500	310	$6.90	$20.65	$20.65	$12.80	$35.63	$8.93	$105.56	$96.56	-8.5%
XLg	1,524	500	500	524	$6.90	$20.65	$20.65	$21.64	$41.45	$10.39	$121.68	$112.68	-7.4%
AnnAvg	899	500	399	0	$6.90	$20.65	$16.48	$0.00	$24.45	$6.13	$74.61	$65.61	-12.1%
ResAvg	785	500	285	0	$6.90	$20.65	$11.77	$0.00	$21.35	$5.35	$66.02	$57.02	-13.6%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$17.00	$0.06116	$0.08310	$0.08310	$0.026030	$0.00000				
Small	694	500	194	0	$17.00	$30.58	$16.08	$0.00	$18.05	$0.00	$81.71	$66.71	$16.58	33.1%
Medium	1,030	500	500	30	$17.00	$30.58	$41.55	$2.49	$26.81	$0.00	$118.43	$103.43	$27.96	37.0%
Large	1,310	500	500	310	$17.00	$30.58	$41.55	$25.76	$34.10	$0.00	$148.99	$133.99	$37.43	38.8%
XLg	1,524	500	500	524	$17.00	$30.58	$41.55	$43.54	$39.67	$0.00	$172.34	$157.34	$44.66	39.6%
AnnAvg	899	500	399	0	$17.00	$30.58	$33.16	$0.00	$23.40	$0.00	$104.14	$89.14	$23.53	35.9%
ResAvg	785	500	285	0	$17.00	$30.58	$23.68	$0.00	$20.43	$0.00	$91.69	$76.69	$19.67	34.5%

SPECIAL LIFELINE RESIDENTIAL ELECTRIC SERVICE RATE R-06-201AF FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
	Mid-Summer				$6.90	$0.06110	$0.06110	$0.06110	$0.033198	$0.00682			
Small	940	500	440	0	$6.90	$30.55	$26.88	$0.00	$31.21	$6.41	$101.95	$92.95	-8.8%
Medium	1,471	500	500	471	$6.90	$30.55	$30.55	$28.75	$48.82	$10.03	$155.60	$146.60	-5.8%
Large	1,869	500	500	869	$6.90	$30.55	$30.55	$53.10	$62.05	$12.75	$195.90	$186.90	-4.6%
XLg	2,135	500	500	1,135	$6.90	$30.55	$30.55	$69.35	$70.88	$14.56	$222.79	$213.79	-4.0%
AnnAvg	899	500	399	0	$6.90	$30.55	$24.38	$0.00	$29.85	$6.13	$97.81	$88.81	-9.2%
ResAvg	1,150	500	500	150	$6.90	$30.55	$30.55	$9.17	$38.18	$7.84	$123.19	$114.19	-7.3%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$17.00	$0.06116	$0.08310	$0.08310	$0.02869	$0.00000				
Small	940	500	440	0	$17.00	$30.58	$36.56	$0.00	$26.97	$0.00	$111.11	$96.11	$3.16	3.4%
Medium	1,471	500	500	471	$17.00	$30.58	$41.55	$39.10	$42.19	$0.00	$170.42	$155.42	$8.82	6.0%
Large	1,869	500	500	869	$17.00	$30.58	$41.55	$72.21	$53.63	$0.00	$214.97	$199.97	$13.07	7.0%
XLg	2,135	500	500	1,135	$17.00	$30.58	$41.55	$94.32	$61.26	$0.00	$244.71	$229.71	$15.92	7.4%
AnnAvg	899	500	399	0	$17.00	$30.58	$33.16	$0.00	$25.80	$0.00	$106.54	$91.54	$2.73	3.1%
ResAvg	1,150	500	500	150	$17.00	$30.58	$41.55	$12.47	$33.00	$0.00	$134.60	$119.60	$5.41	4.7%

SPECIAL LIFELINE RESIDENTIAL ELECTRIC SERVICE RATE R-08-201A FROZEN

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
					$6.90	$0.04130	$0.04130	$0.04130	$0.027198	$0.00682			
Small	1,201	500	500	201	$6.90	$20.65	$20.65	$8.28	$32.65	$8.19	$97.32	$68.12	-30.0%
Medium	1,630	500	500	630	$6.90	$20.65	$20.65	$26.02	$44.33	$11.12	$129.67	$90.77	-30.0%
Large	2,051	500	500	1,051	$6.90	$20.65	$20.65	$43.41	$55.78	$13.99	$161.38	$145.24	-10.0%
XLg	2,310	500	500	1,310	$6.90	$20.65	$20.65	$54.10	$62.83	$15.75	$180.88	$162.79	-10.0%
AnnAvg	1,382	500	500	382	$6.90	$20.65	$20.65	$15.78	$37.59	$9.43	$111.00	$77.70	-30.0%
ResAvg	785	500	285	0	$6.90	$20.65	$11.77	$0.00	$21.35	$5.35	$66.02	$42.91	-35.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$17.00	$0.06116	$0.08310	$0.08310	$0.026030	$0.00000				
Small	1,201	500	500	201	$17.00	$30.58	$41.55	$16.66	$31.25	$0.00	$137.04	$106.04	$37.92	55.7%
Medium	1,630	500	500	630	$17.00	$30.58	$41.55	$52.35	$42.43	$0.00	$183.91	$152.91	$62.14	68.5%
Large	2,051	500	500	1,051	$17.00	$30.58	$41.55	$87.34	$53.39	$0.00	$229.86	$198.86	$53.62	36.9%
XLg	2,310	500	500	1,310	$17.00	$30.58	$41.55	$108.86	$60.13	$0.00	$258.12	$227.12	$64.33	39.5%
AnnAvg	1,382	500	500	382	$17.00	$30.58	$41.55	$31.76	$35.98	$0.00	$156.87	$125.87	$48.17	62.0%
ResAvg	785	500	285	0	$17.00	$30.58	$23.68	$0.00	$20.43	$0.00	$91.69	$60.69	$17.78	41.4%

SPECIAL LIFELINE RESIDENTIAL ELECTRIC SERVICE RATE R-08-201A FROZEN

Summer

	BILL IMPACTS CURRENT RATES												
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
	Mid-Summer				$6.90	$0.06110	$0.06110	$0.06110	$0.033198	$0.00682			
Small	1,586	500	500	586	$6.90	$30.55	$30.55	$35.80	$52.65	$10.82	$167.27	$117.09	-30.0%
Medium	2,062	500	500	1,062	$6.90	$30.55	$30.55	$64.89	$68.45	$14.06	$215.40	$193.86	-10.0%
Large	2,487	500	500	1,487	$6.90	$30.55	$30.55	$90.86	$82.56	$16.96	$258.38	$232.54	-10.0%
XLg	2,710	500	500	1,710	$6.90	$30.55	$30.55	$104.48	$89.97	$18.48	$280.93	$252.84	-10.0%
AnnAvg	1,382	500	500	382	$6.90	$30.55	$30.55	$23.35	$45.88	$9.43	$146.66	$102.66	-30.0%
ResAvg	1,150	500	500	150	$6.90	$30.55	$30.55	$9.17	$38.18	$7.84	$123.19	$86.23	-30.0%

	BILL IMPACTS PROPOSED RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000						
					$17.00	$0.06116	$0.08310	$0.08310	$0.028694	$0.00000			$ Change	% Change
Small	1,586	500	500	586	$17.00	$30.58	$41.55	$48.70	$45.51	$0.00	$183.34	$152.34	$35.25	30.1%
Medium	2,062	500	500	1,062	$17.00	$30.58	$41.55	$88.25	$59.17	$0.00	$236.55	$205.55	$11.69	6.0%
Large	2,487	500	500	1,487	$17.00	$30.58	$41.55	$123.57	$71.36	$0.00	$284.06	$253.06	$20.52	8.8%
XLg	2,710	500	500	1,710	$17.00	$30.58	$41.55	$142.10	$77.76	$0.00	$308.99	$277.99	$25.15	9.9%
AnnAvg	1,382	500	500	382	$17.00	$30.58	$41.55	$31.76	$39.66	$0.00	$160.55	$129.55	$26.89	26.2%
ResAvg	1,150	500	500	150	$17.00	$30.58	$41.55	$12.47	$33.00	$0.00	$134.60	$103.60	$17.37	20.1%

SPECIAL RESIDENTIAL ELECTRIC SERVICE TIME OF USE RATE R-201B

Winter

	BILL IMPACTS CURRENT RATES										
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill
		500	1000	>1000		500	1000	>1000			
On-Peak	0.27				$11.50	$0.04830	$0.04830	$0.04830	$0.032893	$0.00682	
Off-Peak	0.73					$0.03550	$0.03550	$0.03550	$0.027092		
Small	838	500	338	0	$11.50	$19.47	$13.14	$0.00	$24.00	$5.71	$73.82
Medium	1,258	500	500	258	$11.50	$19.47	$19.47	$10.05	$36.04	$8.58	$105.11
Large	1,800	500	500	800	$11.50	$19.47	$19.47	$31.15	$51.57	$12.28	$145.44
XLg	2,221	500	500	1,221	$11.50	$19.47	$19.47	$47.55	$63.63	$15.15	$176.77
AnnAvg	1,097	500	500	97	$11.50	$19.47	$19.47	$3.76	$31.42	$7.48	$93.10
ResAvg	785	500	285	0	$11.50	$19.47	$11.10	$0.00	$22.49	$5.35	$69.91

	BILL IMPACTS PROPOSED RATES												
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill		
		500	1000	>1000		500	1000	>1000					
On-Peak	0.27				$17.00	$0.06116	$0.08310	$0.08310	$0.027114	$0.00000			
Off-Peak	0.73					$0.06116	$0.08310	$0.08310	$0.022474			$ Change	% Change
Small	838	500	338	0	$17.00	$30.58	$28.05	$0.00	$19.87	$0.00	$95.50	$21.68	29.4%
Medium	1,258	500	500	258	$17.00	$30.58	$41.55	$21.44	$29.84	$0.00	$140.41	$35.30	33.6%
Large	1,800	500	500	800	$17.00	$30.58	$41.55	$66.48	$42.70	$0.00	$198.31	$52.87	36.4%
XLg	2,221	500	500	1,221	$17.00	$30.58	$41.55	$101.47	$52.68	$0.00	$243.28	$66.51	37.6%
AnnAvg	1,097	500	500	97	$17.00	$30.58	$41.55	$8.02	$26.01	$0.00	$123.16	$30.06	32.3%
ResAvg	785	500	285	0	$17.00	$30.58	$23.68	$0.00	$18.62	$0.00	$89.88	$19.97	28.6%

SPECIAL RESIDENTIAL ELECTRIC SERVICE TIME OF USE RATE R-201B

Summer

	BILL IMPACTS CURRENT RATES										
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill
		500	1000	>1000	$11.50	500	1000	>1000			
On-Peak	0.23					$0.05680	$0.05680	$0.05680	$0.050669	$0.00682	
Off-Peak	0.77					$0.04400	$0.04400	$0.04400	$0.026679		
Small	1,066	500	500	66	$11.50	$23.45	$23.45	$3.10	$34.25	$7.27	$103.02
Medium	1,609	500	500	609	$11.50	$23.45	$23.45	$28.57	$51.69	$10.97	$149.63
Large	2,283	500	500	1,283	$11.50	$23.45	$23.45	$60.18	$73.34	$15.57	$207.49
XLg	2,790	500	500	1,790	$11.50	$23.45	$23.45	$83.96	$89.63	$19.03	$251.02
AnnAvg	1,097	500	500	97	$11.50	$23.45	$23.45	$4.53	$35.23	$7.48	$105.64
ResAvg	1,150	500	500	150	$11.50	$23.45	$23.45	$7.04	$36.94	$7.84	$110.22

	BILL IMPACTS PROPOSED RATES												
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill		
		500	1000	>1000		500	1000	>1000					
On-Peak	0.23				$17.00	$0.06116	$0.08310	$0.08310	$0.041328	$0.00000			
Off-Peak	0.77					$0.06116	$0.08310	$0.08310	$0.021400			$ Change	% Change
Small	1,066	500	500	66	$17.00	$30.58	$41.55	$5.48	$27.63	$0.00	$122.24	$19.22	18.7%
Medium	1,609	500	500	609	$17.00	$30.58	$41.55	$50.61	$41.71	$0.00	$181.45	$31.82	21.3%
Large	2,283	500	500	1,283	$17.00	$30.58	$41.55	$106.62	$59.18	$0.00	$254.93	$47.44	22.9%
XLg	2,790	500	500	1,790	$17.00	$30.58	$41.55	$148.75	$72.33	$0.00	$310.21	$59.19	23.6%
AnnAvg	1,097	500	500	97	$17.00	$30.58	$41.55	$8.02	$28.43	$0.00	$125.58	$19.94	18.9%
ResAvg	1,150	500	500	150	$17.00	$30.58	$41.55	$12.47	$29.81	$0.00	$131.41	$21.19	19.2%

SPECIAL LIFELINE RESIDENTIAL ELECTRIC SERVICE TIME OF USE RATE R-201BL

Winter

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.27				$11.50	$0.04830	$0.04830	$0.04830	$0.032893	$0.00682			
Off-Peak	0.73					$0.03550	$0.03550	$0.03550	$0.027092				
Small	915	500	415	0	$11.50	$19.47	$16.16	$0.00	$26.22	$6.24	$79.59	$70.59	-11.3%
Medium	1,231	500	500	231	$11.50	$19.47	$19.47	$9.00	$35.27	$8.40	$103.11	$94.11	-8.7%
Large	1,524	500	500	524	$11.50	$19.47	$19.47	$20.40	$43.66	$10.39	$124.89	$115.89	-7.2%
XLg	2,733	500	500	1,733	$11.50	$19.47	$19.47	$67.48	$78.30	$18.64	$214.86	$205.86	-4.2%
AnnAvg	1,370	500	500	370	$11.50	$19.47	$19.47	$14.41	$39.25	$9.34	$113.44	$104.44	-7.9%
ResAvg	785	500	285	0	$11.50	$19.47	$11.10	$0.00	$22.49	$5.35	$69.91	$60.91	-12.9%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.27				$17.00	$0.06116	$0.08310	$0.08310	$0.027114	$0.00000				
Off-Peak	0.73					$0.06116	$0.08310	$0.08310	$0.022474					
Small	915	500	415	0	$17.00	$30.58	$34.49	$0.00	$21.70	$0.00	$103.77	$88.77	$18.18	25.8%
Medium	1,231	500	500	231	$17.00	$30.58	$41.55	$19.20	$29.20	$0.00	$137.53	$122.53	$28.42	30.2%
Large	1,524	500	500	524	$17.00	$30.58	$41.55	$43.54	$36.15	$0.00	$168.82	$153.82	$37.93	32.7%
XLg	2,733	500	500	1,733	$17.00	$30.58	$41.55	$144.01	$64.83	$0.00	$297.97	$282.97	$77.11	37.5%
AnnAvg	1,370	500	500	370	$17.00	$30.58	$41.55	$30.74	$32.50	$0.00	$152.37	$137.37	$32.93	31.5%
ResAvg	785	500	285	0	$17.00	$30.58	$23.68	$0.00	$18.62	$0.00	$89.88	$74.88	$13.97	22.9%

Tucson Electric Power Company
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending June 30, 2015

Summer

SPECIAL LIFELINE RESIDENTIAL ELECTRIC SERVICE TIME OF USE RATE R-201BL

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.23				$11.50	$0.05680	$0.05680	$0.05680	$0.050669	$0.00682			
Off-Peak	0.77					$0.04400	$0.04400	$0.04400	$0.026679				
Small	1,119	500	500	119	$11.50	$23.45	$23.45	$5.58	$35.95	$7.63	$107.56	$98.56	-8.4%
Medium	3,060	500	500	2,060	$11.50	$23.45	$23.45	$96.63	$98.30	$20.87	$274.20	$265.20	-3.3%
Large	3,869	500	500	2,869	$11.50	$23.45	$23.45	$134.57	$124.29	$26.39	$343.65	$334.65	-2.6%
XLg	3,869	500	500	2,869	$11.50	$23.45	$23.45	$134.57	$124.29	$26.39	$343.65	$334.65	-2.6%
AnnAvg	1,370	500	500	370	$11.50	$23.45	$23.45	$17.35	$44.01	$9.34	$129.10	$120.10	-7.0%
ResAvg	1,150	500	500	150	$11.50	$23.45	$23.45	$7.04	$36.94	$7.84	$110.22	$101.22	-8.2%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.23				$17.00	$0.06116	$0.08310	$0.08310	$0.041328	$0.00000				
Off-Peak	0.77					$0.06116	$0.08310	$0.08310	$0.021400					
Small	1,119	500	500	119	$17.00	$30.58	$41.55	$9.89	$29.01	$0.00	$128.03	$113.03	$14.47	14.7%
Medium	3,060	500	500	2,060	$17.00	$30.58	$41.55	$171.19	$79.33	$0.00	$339.65	$324.65	$59.45	22.4%
Large	3,869	500	500	2,869	$17.00	$30.58	$41.55	$238.41	$100.30	$0.00	$427.84	$412.84	$78.19	23.4%
XLg	3,869	500	500	2,869	$17.00	$30.58	$41.55	$238.41	$100.30	$0.00	$427.84	$412.84	$78.19	23.4%
AnnAvg	1,370	500	500	370	$17.00	$30.58	$41.55	$30.74	$35.51	$0.00	$155.38	$140.38	$20.28	16.9%
ResAvg	1,150	500	500	150	$17.00	$30.58	$41.55	$12.47	$29.81	$0.00	$131.41	$116.41	$15.19	15.0%

SPECIAL LIFELINE RESIDENTIAL ELECTRIC SERVICE TIME OF USE RATE R-06-201BF

Winter

	BILL IMPACTS CURRENT RATES												
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.24				$8.78	$0.06520	$0.06520	$0.06520	$0.040698	$0.00682			
Shldr-Peak	N/A												
Off-Peak	0.76					$0.01530	$0.01530	$0.01530	$0.020698				
Small	515	500	15	0	$8.78	$13.52	$0.41	$0.00	$13.08	$3.51	$39.30	$30.30	-22.9%
Medium	1,064	500	500	64	$8.78	$13.52	$13.52	$1.73	$27.03	$7.26	$71.84	$62.84	-12.5%
Large	1,311	500	500	311	$8.78	$13.52	$13.52	$8.40	$33.29	$8.94	$86.45	$77.45	-10.4%
XLg	1,647	500	500	647	$8.78	$13.52	$13.52	$17.50	$41.84	$11.23	$106.39	$97.39	-8.5%
AnnAvg	745	500	245	0	$8.78	$13.52	$6.62	$0.00	$18.92	$5.08	$52.92	$43.92	-17.0%
ResAvg	785	500	285	0	$8.78	$13.52	$7.71	$0.00	$19.94	$5.35	$55.30	$46.30	-16.3%

	BILL IMPACTS PROPOSED RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000						
On-Peak	0.27				$17.00	$0.06116	$0.08310	$0.08310	$0.028809	$0.00000				
Off-Peak	0.73					$0.06116	$0.08310	$0.08310	$0.023878				$ Change	% Change
Small	515	500	15	0	$17.00	$30.58	$1.25	$0.00	$12.98	$0.00	$61.81	$46.81	$16.51	54.5%
Medium	1,064	500	500	64	$17.00	$30.58	$41.55	$5.32	$26.82	$0.00	$121.27	$106.27	$43.43	69.1%
Large	1,311	500	500	311	$17.00	$30.58	$41.55	$25.81	$33.03	$0.00	$147.97	$132.97	$55.52	71.7%
XLg	1,647	500	500	647	$17.00	$30.58	$41.55	$53.77	$41.51	$0.00	$184.41	$169.41	$72.02	74.0%
AnnAvg	745	500	245	0	$17.00	$30.58	$20.35	$0.00	$18.77	$0.00	$86.70	$71.70	$27.78	63.3%
ResAvg	785	500	285	0	$17.00	$30.58	$23.68	$0.00	$19.78	$0.00	$91.04	$76.04	$29.74	64.2%

SPECIAL LIFELINE RESIDENTIAL ELECTRIC SERVICE TIME OF USE RATE R-06-201BF

Summer

	BILL IMPACTS CURRENT RATES												
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.18				$8.78	$0.13690	$0.13690	$0.13690	$0.055698	$0.00682			
Shldr-Peak	0.09					$0.07470	$0.07470	$0.07470	$0.048198				
Off-Peak	0.72					$0.03830	$0.03830	$0.03830	$0.023198				
Small	559	500	59	0	$8.78	$29.89	$3.50	$0.00	$17.57	$3.81	$63.55	$54.55	-14.2%
Medium	1,492	500	500	492	$8.78	$29.89	$29.89	$29.41	$46.95	$10.18	$155.10	$146.10	-5.8%
Large	1,824	500	500	824	$8.78	$29.89	$29.89	$49.26	$57.39	$12.44	$187.65	$178.65	-4.8%
XLg	1,862	500	500	862	$8.78	$29.89	$29.89	$51.54	$58.59	$12.70	$191.39	$182.39	-4.7%
AnnAvg	745	500	245	0	$8.78	$29.89	$14.64	$0.00	$23.44	$5.08	$81.83	$72.83	-11.0%
ResAvg	1,150	500	500	150	$8.78	$29.89	$29.89	$8.97	$36.19	$7.84	$121.56	$112.56	-7.4%

	BILL IMPACTS PROPOSED RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.23				$17.00	$0.06116	$0.08310	$0.08310	$0.043911	$0.00000				
Off-Peak	0.77					$0.06116	$0.08310	$0.08310	$0.022738					
Small	559	500	59	0	$17.00	$30.58	$4.86	$0.00	$15.38	$0.00	$67.82	$52.82	-$1.73	-3.2%
Medium	1,492	500	500	492	$17.00	$30.58	$41.55	$40.88	$41.10	$0.00	$171.11	$156.11	$10.01	6.9%
Large	1,824	500	500	824	$17.00	$30.58	$41.55	$68.47	$50.24	$0.00	$207.84	$192.84	$14.19	7.9%
XLg	1,862	500	500	862	$17.00	$30.58	$41.55	$71.63	$51.29	$0.00	$212.05	$197.05	$14.66	8.0%
AnnAvg	745	500	245	0	$17.00	$30.58	$20.35	$0.00	$20.52	$0.00	$88.45	$73.45	$0.62	0.9%
ResAvg	1,150	500	500	150	$17.00	$30.58	$41.55	$12.47	$31.68	$0.00	$133.28	$118.28	$5.72	5.1%

PREPAY ELECTRIC SERVICE

WINTER

BILL IMPACTS CURRENT R-01 RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill
		500	1000	3500	>3500		500	1000	3500	>3500			
						$10.00	$0.05620	$0.06520	$0.07810	$0.08710	$0.031532	$0.00682	
Small	520	500	20	0	0	$10.00	$28.10	$1.30	$0.00	$0.00	$16.40	$3.55	$59.35
Medium	840	500	340	0	0	$10.00	$28.10	$22.17	$0.00	$0.00	$26.49	$5.73	$92.49
Large	1,250	500	500	250	0	$10.00	$28.10	$32.60	$19.53	$0.00	$39.42	$8.53	$138.18
XLg	1,564	500	500	564	0	$10.00	$28.10	$32.60	$44.05	$0.00	$49.32	$10.67	$174.74
AnnAvg	785	500	285	0	0	$10.00	$28.10	$18.58	$0.00	$0.00	$24.75	$5.35	$86.78
ResAvg	785	500	285	0	0	$10.00	$28.10	$18.58	$0.00	$0.00	$24.75	$5.35	$86.78

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh/day) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill		
		20	>20			($/day)	20	>20							
						$0.74	$0.06500	$0.08400			$0.032537	$0.00000			
														$ Change	% Change
Small	520	520	0			$22.20	$33.80	$0.00			$16.92	$0.00	$72.92	$13.57	22.9%
Medium	840	600	240			$22.20	$39.00	$20.16			$27.33	$0.00	$108.69	$16.20	17.5%
Large	1,250	600	650			$22.20	$39.00	$54.60			$40.67	$0.00	$156.47	$18.29	13.2%
XLg	1,564	600	964			$22.20	$39.00	$80.98			$50.89	$0.00	$193.07	$18.33	10.5%
AnnAvg	785	600	185			$22.20	$39.00	$15.54			$25.54	$0.00	$102.28	$15.50	17.9%
ResAvg	785	600	185			$22.20	$39.00	$15.54			$25.54	$0.00	$102.28	$15.50	17.9%

Note: Prepay Electric Service bill calculations assume 30 days per month.

PREPAY ELECTRIC SERVICE

SUMMER

	BILL IMPACTS CURRENT R-01 RATES												
	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill
		500	1000	3500	>3500		500	1000	3500	>3500			
						$10.00	$0.05620	$0.06720	$0.07980	$0.08820	$0.035111	$0.00682	
Small	822	500	322	0	0	$10.00	$28.10	$21.64	$0.00	$0.00	$28.86	$5.61	$94.21
Medium	1,384	500	500	384	0	$10.00	$28.10	$33.60	$30.64	$0.00	$48.59	$9.44	$160.37
Large	1,997	500	500	997	0	$10.00	$28.10	$33.60	$79.56	$0.00	$70.12	$13.62	$235.00
XLg	2,430	500	500	1,430	0	$10.00	$28.10	$33.60	$114.11	$0.00	$85.32	$16.57	$287.70
AnnAvg	785	500	285	0	0	$10.00	$28.10	$19.15	$0.00	$0.00	$27.56	$5.35	$90.16
ResAvg	1,150	500	500	150	0	$10.00	$28.10	$33.60	$11.97	$0.00	$40.38	$7.84	$131.89

	BILL IMPACTS PROPOSED RATES														
	kWh	Delivery (kWh/day) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill		
		20	>20			($/day)	20	>20							
						$0.74	$0.06500	$0.08400			$0.035868	$0.00000			
														$ Change	% Change
Small	822	600	222			$22.20	$39.00	$18.65			$29.48	$0.00	$109.33	$15.12	16.0%
Medium	1,384	600	784			$22.20	$39.00	$65.86			$49.64	$0.00	$176.70	$16.33	10.2%
Large	1,997	600	1,397			$22.20	$39.00	$117.35			$71.63	$0.00	$250.18	$15.18	6.5%
XLg	2,430	600	1,830			$22.20	$39.00	$153.72			$87.16	$0.00	$302.08	$14.38	5.0%
AnnAvg	785	600	185			$22.20	$39.00	$15.54			$28.16	$0.00	$104.90	$14.74	16.3%
ResAvg	1,150	600	550			$22.20	$39.00	$46.20			$41.25	$0.00	$148.65	$16.76	12.7%

Note: Prepay Electric Service bill calculations assume 30 days per month.

Small General Service RATE GS-10

WINTER

	BILL IMPACTS CURRENT RATES								
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill
		500	>500		500	>500			
				$15.50	$0.05700	$0.07900	$0.031532	$0.00682	
Xsm	190	190	0	$15.50	$10.83	$0.00	$5.99	$1.30	$33.62
Small	687	500	187	$15.50	$28.50	$14.77	$21.66	$4.69	$85.12
Medium	1,744	500	1,244	$15.50	$28.50	$98.28	$54.99	$11.89	$209.16
Large	3,680	500	3,180	$15.50	$28.50	$251.22	$116.04	$25.10	$436.36
XLg	5,157	500	4,657	$15.50	$28.50	$367.90	$162.61	$35.17	$609.68
AnnAvg	1,568	500	1,068	$15.50	$28.50	$84.37	$49.44	$10.69	$188.50
SGSAvg	1,340	500	840	$15.50	$28.50	$66.36	$42.25	$9.14	$161.75

	BILL IMPACTS PROPOSED RATES										
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill		
		500	>500		500	>500					
				$27.00	$0.07190	$0.09290	$0.032537	$0.00000			
										$ Change	% Change
Xsm	190	190	0	$27.00	$13.66	$0.00	$6.18	$0.00	$46.84	$13.22	39.3%
Small	687	500	187	$27.00	$35.95	$17.37	$22.35	$0.00	$102.67	$17.55	20.6%
Medium	1,744	500	1,244	$27.00	$35.95	$115.57	$56.74	$0.00	$235.26	$26.10	12.5%
Large	3,680	500	3,180	$27.00	$35.95	$295.42	$119.74	$0.00	$478.11	$41.75	9.6%
XLg	5,157	500	4,657	$27.00	$35.95	$432.64	$167.79	$0.00	$663.38	$53.70	8.8%
AnnAvg	1,568	500	1,068	$27.00	$35.95	$99.22	$51.02	$0.00	$213.19	$24.69	13.1%
SGSAvg	1,340	500	840	$27.00	$35.95	$78.04	$43.60	$0.00	$184.59	$22.84	14.1%

Small General Service RATE GS-10

SUMMER

	BILL IMPACTS CURRENT RATES								
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill
		500	>500		500	>500			
				$15.50	$0.07700	$0.09780	$0.035111	$0.00682	
Xsm	216	216	0	$15.50	$16.63	$0.00	$7.58	$1.47	$41.18
Small	882	500	382	$15.50	$38.50	$37.36	$30.97	$6.02	$128.35
Medium	2,354	500	1,854	$15.50	$38.50	$181.32	$82.65	$16.05	$334.02
Large	4,820	500	4,320	$15.50	$38.50	$422.50	$169.24	$32.87	$678.61
XLg	6,690	500	6,190	$15.50	$38.50	$605.38	$234.89	$45.63	$939.90
AnnAvg	1,568	500	1,068	$15.50	$38.50	$104.45	$55.05	$10.69	$224.19
SGSAvg	1,886	500	1,386	$15.50	$38.50	$135.51	$66.21	$12.86	$268.58

	BILL IMPACTS PROPOSED RATES										
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill		
		500	>500		500	>500					
				$27.00	$0.08185	$0.10185	$0.035868	$0.00000			
										$ Change	% Change
Xsm	216	216	0	$27.00	$17.68	$0.00	$7.75	$0.00	$52.43	$11.25	27.3%
Small	882	500	382	$27.00	$40.93	$38.91	$31.64	$0.00	$138.48	$10.13	7.9%
Medium	2,354	500	1,854	$27.00	$40.93	$188.83	$84.43	$0.00	$341.19	$7.17	2.1%
Large	4,820	500	4,320	$27.00	$40.93	$439.99	$172.88	$0.00	$680.80	$2.19	0.3%
XLg	6,690	500	6,190	$27.00	$40.93	$630.45	$239.96	$0.00	$938.34	-$1.56	-0.2%
AnnAvg	1,568	500	1,068	$27.00	$40.93	$108.78	$56.24	$0.00	$232.95	$8.76	3.9%
SGSAvg	1,886	500	1,386	$27.00	$40.93	$141.12	$67.63	$0.00	$276.68	$8.10	3.0%

SMALL GENERAL SERVICE DEMAND

WINTER

BILL IMPACTS CURRENT GS-10 RATES

	Load Factor	kWh	Delivery (kWh) TIERS		kW	Delivery (kW)		Basic Service Charge	Delivery (Energy)		Delivery (Demand)		Base Fuel	PPFAC	Net Bill
			500	>500					500	>500					
								$15.50	$0.05700	$0.07900			$0.031532	$0.00682	
Xsm	0.21	190	190	0	1.2			$15.50	$10.83	$0.00			$5.99	$1.30	$33.62
Small	0.29	687	500	187	3.2			$15.50	$28.50	$14.77			$21.66	$4.69	$85.12
Medium	0.37	1,744	500	1,244	6.5			$15.50	$28.50	$98.28			$54.99	$11.89	$209.16
Large	0.45	3,680	500	3,180	11.3			$15.50	$28.50	$251.22			$116.04	$25.10	$436.36
XLg	0.49	5,157	500	4,657	14.5			$15.50	$28.50	$367.90			$162.61	$35.17	$609.68
AnnAvg	0.36	1,568	500	1,068	6.0			$15.50	$28.50	$84.37			$49.44	$10.69	$188.50
SGSAvg	0.35	1,340	500	840	5.3			$15.50	$28.50	$66.36			$42.25	$9.14	$161.75

BILL IMPACTS PROPOSED RATES

	Load Factor	kWh	Delivery (kWh) TIERS		kW	Delivery (kW)		Basic Service Charge	Delivery (Energy)		Delivery (Demand)		Base Fuel	PPFAC	Net Bill		
			500	>500		7.0	> 7.0		500	>500	7.0	> 7.0					
								$27.00	$0.04777	$0.04777	$9.60	$13.75	$0.032537	$0.00000			
																$ Change	% Change
Xsm	0.21	190	190	0	1.2	1.2	0.0	$27.00	$9.08	$0.00	$11.90	$0.00	$6.18	$0.00	$54.16	$20.54	61.1%
Small	0.29	687	500	187	3.2	3.2	0.0	$27.00	$23.89	$8.93	$31.01	$0.00	$22.35	$0.00	$113.18	$28.06	33.0%
Medium	0.37	1,744	500	1,244	6.5	6.5	0.0	$27.00	$23.89	$59.43	$62.11	$0.00	$56.74	$0.00	$229.17	$20.01	9.6%
Large	0.45	3,680	500	3,180	11.3	7.0	4.3	$27.00	$23.89	$151.91	$67.20	$58.85	$119.74	$0.00	$448.59	$12.23	2.8%
XLg	0.49	5,157	500	4,657	14.5	7.0	7.5	$27.00	$23.89	$222.46	$67.20	$103.26	$167.79	$0.00	$611.60	$1.92	0.3%
AnnAvg	0.36	1,568	500	1,068	6.0	6.0	0.0	$27.00	$23.89	$51.02	$57.41	$0.00	$51.02	$0.00	$210.34	$21.84	11.6%
SGSAvg	0.35	1,340	500	840	5.3	5.3	0.0	$27.00	$23.89	$40.13	$51.07	$0.00	$43.60	$0.00	$185.69	$23.94	14.8%

SMALL GENERAL SERVICE DEMAND

SUMMER

BILL IMPACTS CURRENT GS-10 RATES

	Load Factor	kWh	Delivery (kWh) TIERS		kW	Delivery (kW)		Basic Service Charge	Delivery (Energy)		Delivery (Demand)		Base Fuel	PPFAC	Net Bill
			500	>500					500	>500					
								$15.50	$0.07700	$0.09780			$0.035111	$0.00682	
Xsm	0.22	216	216	0	1.4			$15.50	$16.63	$0.00			$7.58	$1.47	$41.18
Small	0.31	882	500	382	3.9			$15.50	$38.50	$37.36			$30.97	$6.02	$128.35
Medium	0.40	2,354	500	1,854	8.1			$15.50	$38.50	$181.32			$82.65	$16.05	$334.02
Large	0.48	4,820	500	4,320	13.8			$15.50	$38.50	$422.50			$169.24	$32.87	$678.61
XLg	0.52	6,690	500	6,190	17.6			$15.50	$38.50	$605.38			$234.89	$45.63	$939.90
AnnAvg	0.36	1,568	500	1,068	6.0			$15.50	$38.50	$104.45			$55.05	$10.69	$224.19
SGSAvg	0.38	1,886	500	1,386	6.9			$15.50	$38.50	$135.51			$66.21	$12.86	$268.58

BILL IMPACTS PROPOSED RATES

	Load Factor	kWh	Delivery (kWh) TIERS		kW	Delivery (kW)		Basic Service Charge	Delivery (Energy)		Delivery (Demand)		Base Fuel	PPFAC	Net Bill		
			500	>500		7.0	> 7.0		500	>500	7.0	> 7.0					
								$27.00	$0.05777	$0.05777	$9.60	$13.75	$0.035868	$0.00000			
																$ Change	% Change
Xsm	0.22	216	216	0	1.4	1.4	0.0	$27.00	$12.48	$0.00	$13.06	$0.00	$7.75	$0.00	$60.29	$19.11	46.4%
Small	0.31	882	500	382	3.9	3.9	0.0	$27.00	$28.89	$22.07	$37.34	$0.00	$31.64	$0.00	$146.94	$18.59	14.5%
Medium	0.40	2,354	500	1,854	8.1	7.0	1.1	$27.00	$28.89	$107.11	$67.20	$14.99	$84.43	$0.00	$329.62	-$4.40	-1.3%
Large	0.48	4,820	500	4,320	13.8	7.0	6.8	$27.00	$28.89	$249.57	$67.20	$93.36	$172.88	$0.00	$638.90	-$39.71	-5.9%
XLg	0.52	6,690	500	6,190	17.6	7.0	10.6	$27.00	$28.89	$357.60	$67.20	$145.89	$239.96	$0.00	$866.54	-$73.36	-7.8%
AnnAvg	0.36	1,568	500	1,068	6.0	6.0	0.0	$27.00	$28.89	$61.70	$57.41	$0.00	$56.24	$0.00	$231.24	$7.05	3.1%
SGSAvg	0.38	1,886	500	1,386	6.9	6.9	0.0	$27.00	$28.89	$80.05	$65.86	$0.00	$67.63	$0.00	$269.43	$0.85	0.3%

Small General Service (Municipal Transitional Adjustment) RATE GSM-10

WINTER

	BILL IMPACTS CURRENT RATES								
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill
		500	>500		500	>500			
				$15.50	$0.05700	$0.07900	$0.031532	$0.00682	
Xsm	190	190	0	$15.50	$10.83	$0.00	$5.99	$1.30	$30.63
Small	687	500	187	$15.50	$28.50	$14.77	$21.66	$4.69	$73.63
Medium	1,744	500	1,244	$15.50	$28.50	$98.28	$54.99	$11.89	$177.21
Large	3,680	500	3,180	$15.50	$28.50	$251.22	$116.04	$25.10	$366.92
XLg	5,157	500	4,657	$15.50	$28.50	$367.90	$162.61	$35.17	$511.64
AnnAvg	1,568	500	1,068	$15.50	$28.50	$84.37	$49.44	$10.69	$159.96
SGSAvg	1,340	500	840	$15.50	$28.50	$66.36	$42.25	$9.14	$137.62

	BILL IMPACTS PROPOSED RATES										
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill		
		500	>500		500	>500					
				$27.00	$0.07190	$0.09290	$0.032537	$0.00000			
										$ Change	% Change
Xsm	190	190	0	$27.00	$13.66	$0.00	$6.18	$0.00	$46.84	$16.21	52.9%
Small	687	500	187	$27.00	$35.95	$17.37	$22.35	$0.00	$102.67	$29.04	39.4%
Medium	1,744	500	1,244	$27.00	$35.95	$115.57	$56.74	$0.00	$235.26	$58.05	32.8%
Large	3,680	500	3,180	$27.00	$35.95	$295.42	$119.74	$0.00	$478.11	$111.19	30.3%
XLg	5,157	500	4,657	$27.00	$35.95	$432.64	$167.79	$0.00	$663.38	$151.74	29.7%
AnnAvg	1,568	500	1,068	$27.00	$35.95	$99.22	$51.02	$0.00	$213.19	$53.24	33.3%
SGSAvg	1,340	500	840	$27.00	$35.95	$78.04	$43.60	$0.00	$184.59	$46.97	34.1%

Small General Service (Municipal Transitional Adjustment) RATE GSM-10

SUMMER

	BILL IMPACTS CURRENT RATES								
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill
		500	>500		500	>500			
				$15.50	$0.07700	$0.09780	$0.035111	$0.00682	
Xsm	216	216	0	$15.50	$16.63	$0.00	$7.58	$1.47	$36.94
Small	882	500	382	$15.50	$38.50	$37.36	$30.97	$6.02	$109.73
Medium	2,354	500	1,854	$15.50	$38.50	$181.32	$82.65	$16.05	$281.46
Large	4,820	500	4,320	$15.50	$38.50	$422.50	$169.24	$32.87	$569.20
XLg	6,690	500	6,190	$15.50	$38.50	$605.38	$234.89	$45.63	$787.37
AnnAvg	1,568	500	1,068	$15.50	$38.50	$104.45	$55.05	$10.69	$189.76
SGSAvg	1,886	500	1,386	$15.50	$38.50	$135.51	$66.21	$12.86	$226.82

	BILL IMPACTS PROPOSED RATES										
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill		
		500	>500		500	>500					
				$27.00	$0.08185	$0.10185	$0.035868	$0.00000			
										$ Change	% Change
Xsm	216	216	0	$27.00	$17.68	$0.00	$7.75	$0.00	$52.43	$15.49	41.9%
Small	882	500	382	$27.00	$40.93	$38.91	$31.64	$0.00	$138.48	$28.75	26.2%
Medium	2,354	500	1,854	$27.00	$40.93	$188.83	$84.43	$0.00	$341.19	$59.73	21.2%
Large	4,820	500	4,320	$27.00	$40.93	$439.99	$172.88	$0.00	$680.80	$111.60	19.6%
XLg	6,690	500	6,190	$27.00	$40.93	$630.45	$239.96	$0.00	$938.34	$150.97	19.2%
AnnAvg	1,568	500	1,068	$27.00	$40.93	$108.78	$56.24	$0.00	$232.95	$43.19	22.8%
SGSAvg	1,886	500	1,386	$27.00	$40.93	$141.12	$67.63	$0.00	$276.68	$49.86	22.0%

Mobile Home Parks Service Rate GS-11 Frozen

WINTER

	BILL IMPACTS CURRENT RATES					
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill
		$15.50	$0.06200	$0.031532	$0.00682	
Xsm	3,067	$15.50	$190.15	$96.71	$20.92	$323.28
Small	6,520	$15.50	$404.24	$205.59	$44.47	$669.80
Medium	11,218	$15.50	$695.52	$353.73	$76.51	$1,141.26
Large	18,640	$15.50	$1,155.68	$587.76	$127.12	$1,886.06
XLg	27,080	$15.50	$1,678.96	$853.89	$184.69	$2,733.04
AnnAvg	13,623	$15.50	$844.60	$429.55	$92.91	$1,382.56
SGSAvg	12,611	$15.50	$781.85	$397.64	$86.00	$1,280.99

	BILL IMPACTS PROPOSED RATES							
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill		
		$27.00	$0.08520	$0.032537	$0.00000			
							$ Change	% Change
Xsm	3,067	$27.00	$261.31	$99.79	$0.00	$388.10	$64.82	20.1%
Small	6,520	$27.00	$555.50	$212.14	$0.00	$794.64	$124.84	18.6%
Medium	11,218	$27.00	$955.77	$365.00	$0.00	$1,347.77	$206.51	18.1%
Large	18,640	$27.00	$1,588.13	$606.49	$0.00	$2,221.62	$335.56	17.8%
XLg	27,080	$27.00	$2,307.22	$881.10	$0.00	$3,215.32	$482.28	17.6%
AnnAvg	13,623	$27.00	$1,160.64	$443.24	$0.00	$1,630.88	$248.32	18.0%
SGSAvg	12,611	$27.00	$1,074.42	$410.31	$0.00	$1,511.73	$230.74	18.0%

Mobile Home Parks Service Rate GS-11 Frozen

SUMMER

	BILL IMPACTS CURRENT RATES					
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill
		$15.50	$0.08200	$0.035111	$0.00682	
Xsm	3,900	$15.50	$319.80	$136.93	$26.60	$498.83
Small	8,480	$15.50	$695.36	$297.74	$57.83	$1,066.43
Medium	17,200	$15.50	$1,410.40	$603.91	$117.30	$2,147.11
Large	26,720	$15.50	$2,191.04	$938.17	$182.23	$3,326.94
XLg	35,920	$15.50	$2,945.44	$1,261.19	$244.97	$4,467.10
AnnAvg	13,623	$15.50	$1,117.05	$478.30	$92.91	$1,703.76
SGSAvg	15,040	$15.50	$1,233.31	$528.08	$102.58	$1,879.47

	BILL IMPACTS PROPOSED RATES							
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill		
		$27.00	$0.08520	$0.035868	$0.00000			
							$ Change	% Change
Xsm	3,900	$27.00	$332.28	$139.89	$0.00	$499.17	$0.34	0.1%
Small	8,480	$27.00	$722.50	$304.16	$0.00	$1,053.66	-$12.77	-1.2%
Medium	17,200	$27.00	$1,465.44	$616.93	$0.00	$2,109.37	-$37.74	-1.8%
Large	26,720	$27.00	$2,276.54	$958.39	$0.00	$3,261.93	-$65.01	-2.0%
XLg	35,920	$27.00	$3,060.38	$1,288.38	$0.00	$4,375.76	-$91.34	-2.0%
AnnAvg	13,623	$27.00	$1,160.64	$488.61	$0.00	$1,676.25	-$27.51	-1.6%
SGSAvg	15,040	$27.00	$1,281.44	$539.47	$0.00	$1,847.91	-$31.56	-1.7%

Municipal Water Pumping Rate GS-43

WINTER

	BILL IMPACTS CURRENT RATES					
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill
		$15.50	$0.04800	$0.031532	$0.00682	
Xsm	90	$15.50	$4.32	$2.84	$0.61	$23.27
Small	1,440	$15.50	$69.12	$45.41	$9.82	$139.85
Medium	10,840	$15.50	$520.32	$341.81	$73.93	$951.56
Large	34,240	$15.50	$1,643.52	$1,079.66	$233.52	$2,972.20
XLg	56,800	$15.50	$2,726.40	$1,791.02	$387.38	$4,920.30
AnnAvg	14,343	$15.50	$688.47	$452.27	$97.82	$1,254.06
SGSAvg	12,251	$15.50	$588.04	$386.30	$83.55	$1,073.39

	BILL IMPACTS PROPOSED RATES							
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill		
		$27.00	$0.06550	$0.032537	$0.00000			
							$ Change	% Change
Xsm	90	$27.00	$5.90	$2.93	$0.00	$35.83	$12.56	54.0%
Small	1,440	$27.00	$94.32	$46.85	$0.00	$168.17	$28.32	20.3%
Medium	10,840	$27.00	$710.02	$352.70	$0.00	$1,089.72	$138.16	14.5%
Large	34,240	$27.00	$2,242.72	$1,114.07	$0.00	$3,383.79	$411.59	13.8%
XLg	56,800	$27.00	$3,720.40	$1,848.10	$0.00	$5,595.50	$675.20	13.7%
AnnAvg	14,343	$27.00	$939.48	$466.68	$0.00	$1,433.16	$179.10	14.3%
SGSAvg	12,251	$27.00	$802.44	$398.61	$0.00	$1,228.05	$154.66	14.4%

Municipal Water Pumping Rate GS-43

SUMMER

	BILL IMPACTS CURRENT RATES					
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill
		$15.50	$0.06800	$0.035111	$0.00682	
Xsm	160	$15.50	$10.85	$5.60	$1.09	$33.04
Small	2,766	$15.50	$188.05	$97.10	$18.86	$319.51
Medium	17,280	$15.50	$1,175.04	$606.72	$117.85	$1,915.11
Large	46,160	$15.50	$3,138.88	$1,620.72	$314.81	$5,089.91
XLg	83,200	$15.50	$5,657.60	$2,921.24	$567.42	$9,161.76
AnnAvg	14,343	$15.50	$975.34	$503.60	$97.82	$1,592.26
SGSAvg	17,209	$15.50	$1,170.21	$604.23	$117.37	$1,907.31

	BILL IMPACTS PROPOSED RATES							
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill		
		$27.00	$0.08550	$0.035868	$0.00000			
							$ Change	% Change
Xsm	160	$27.00	$13.64	$5.72	$0.00	$46.36	$13.32	40.3%
Small	2,766	$27.00	$236.45	$99.19	$0.00	$362.64	$43.13	13.5%
Medium	17,280	$27.00	$1,477.44	$619.80	$0.00	$2,124.24	$209.13	10.9%
Large	46,160	$27.00	$3,946.68	$1,655.67	$0.00	$5,629.35	$539.44	10.6%
XLg	83,200	$27.00	$7,113.60	$2,984.22	$0.00	$10,124.82	$963.06	10.5%
AnnAvg	14,343	$27.00	$1,226.34	$514.46	$0.00	$1,767.80	$175.54	11.0%
SGSAvg	17,209	$27.00	$1,471.37	$617.25	$0.00	$2,115.62	$208.31	10.9%

Municipal Interruptible Water Pumping Rate GS-43

WINTER

	BILL IMPACTS CURRENT RATES					
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill
		$15.50	$0.02700	$0.028420	$0.00682	
Xsm	90	$15.50	$2.43	$2.56	$0.61	$21.10
Small	1,440	$15.50	$38.88	$40.92	$9.82	$105.12
Medium	10,840	$15.50	$292.68	$308.07	$73.93	$690.18
Large	34,240	$15.50	$924.48	$973.10	$233.52	$2,146.60
XLg	56,800	$15.50	$1,533.60	$1,614.26	$387.38	$3,550.74
AnnAvg	14,343	$15.50	$387.27	$407.63	$97.82	$908.22
SGSAvg	12,251	$15.50	$330.78	$348.17	$83.55	$778.00

	BILL IMPACTS PROPOSED RATES							
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill		
		$27.00	$0.04450	$0.029400	$0.00000			
							$ Change	% Change
Xsm	90	$27.00	$4.01	$2.65	$0.00	$33.66	$12.56	59.5%
Small	1,440	$27.00	$64.08	$42.34	$0.00	$133.42	$28.30	26.9%
Medium	10,840	$27.00	$482.38	$318.70	$0.00	$828.08	$137.90	20.0%
Large	34,240	$27.00	$1,523.68	$1,006.66	$0.00	$2,557.34	$410.74	19.1%
XLg	56,800	$27.00	$2,527.60	$1,669.92	$0.00	$4,224.52	$673.78	19.0%
AnnAvg	14,343	$27.00	$638.27	$421.69	$0.00	$1,086.96	$178.74	19.7%
SGSAvg	12,251	$27.00	$545.17	$360.18	$0.00	$932.35	$154.35	19.8%

Municipal Interruptible Water Pumping Rate GS-43

SUMMER

	BILL IMPACTS CURRENT RATES					
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill
		$15.50	$0.04200	$0.031310	$0.00682	
Xsm	160	$15.50	$6.70	$4.99	$1.09	$28.28
Small	2,766	$15.50	$116.15	$86.59	$18.86	$237.10
Medium	17,280	$15.50	$725.76	$541.04	$117.85	$1,400.15
Large	46,160	$15.50	$1,938.72	$1,445.27	$314.81	$3,714.30
XLg	83,200	$15.50	$3,494.40	$2,604.99	$567.42	$6,682.31
AnnAvg	14,343	$15.50	$602.41	$449.08	$97.82	$1,164.81
SGSAvg	17,209	$15.50	$722.78	$538.81	$117.37	$1,394.46

	BILL IMPACTS PROPOSED RATES							
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill		
		$27.00	$0.05950	$0.032100	$0.00000			
							$ Change	% Change
Xsm	160	$27.00	$9.49	$5.12	$0.00	$41.61	$13.33	47.1%
Small	2,766	$27.00	$164.55	$88.77	$0.00	$280.32	$43.22	18.2%
Medium	17,280	$27.00	$1,028.16	$554.69	$0.00	$1,609.85	$209.70	15.0%
Large	46,160	$27.00	$2,746.52	$1,481.74	$0.00	$4,255.26	$540.96	14.6%
XLg	83,200	$27.00	$4,950.40	$2,670.72	$0.00	$7,648.12	$965.81	14.5%
AnnAvg	14,343	$27.00	$853.42	$460.42	$0.00	$1,340.84	$176.03	15.1%
SGSAvg	17,209	$27.00	$1,023.94	$552.41	$0.00	$1,603.35	$208.89	15.0%

SMALL GENERAL SERVICE TIME OF USE RATE GS-76

Winter

	BILL IMPACTS CURRENT RATES								
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill
		500	>500		500	>500			
On-Peak	0.24			$17.50	$0.08140	$0.08140	$0.032893	$0.00682	
Off-Peak	0.76				$0.06490	$0.06490	$0.027092		
Xsm	190	190	0	$17.50	$13.07	$0.00	$5.41	$1.30	$37.28
Small	687	500	187	$17.50	$34.40	$12.87	$19.55	$4.69	$89.01
Medium	1,744	500	1,244	$17.50	$34.40	$85.59	$49.64	$11.89	$199.02
Large	3,680	500	3,180	$17.50	$34.40	$218.78	$104.74	$25.10	$400.52
XLg	5,157	500	4,657	$17.50	$34.40	$320.40	$146.78	$35.17	$554.25
AnnAvg	1,568	500	1,068	$17.50	$34.40	$73.48	$44.63	$10.69	$180.70
SGSAvg	1,340	500	840	$17.50	$34.40	$57.79	$38.14	$9.14	$156.97

	BILL IMPACTS PROPOSED RATES										
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill		
		500	>500		500	>500					
On-Peak	0.24			$27.00	$0.07190	$0.09290	$0.033893	$0.00000			
Off-Peak	0.76				$0.07190	$0.09290	$0.028092			$ Change	% Change
Xsm	190	190	0	$27.00	$13.66	$0.00	$5.60	$0.00	$46.26	$8.98	24.1%
Small	687	500	187	$27.00	$35.95	$17.37	$20.24	$0.00	$100.56	$11.55	13.0%
Medium	1,744	500	1,244	$27.00	$35.95	$115.57	$51.38	$0.00	$229.90	$30.88	15.5%
Large	3,680	500	3,180	$27.00	$35.95	$295.42	$108.42	$0.00	$466.79	$66.27	16.5%
XLg	5,157	500	4,657	$27.00	$35.95	$432.64	$151.94	$0.00	$647.53	$93.28	16.8%
AnnAvg	1,568	500	1,068	$27.00	$35.95	$99.22	$46.20	$0.00	$208.37	$27.67	15.3%
SGSAvg	1,340	500	840	$27.00	$35.95	$78.04	$39.48	$0.00	$180.47	$23.50	15.0%

SMALL GENERAL SERVICE TIME OF USE RATE GS-76

Summer

	BILL IMPACTS CURRENT RATES								
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill
		500	>500	$17.50	500	>500			
On-Peak	0.20				$0.09910	$0.09910	$0.050669	$0.00682	
Off-Peak	0.80				$0.08490	$0.08490	$0.026679		
Xsm	216	216	0	$17.50	$18.96	$0.00	$6.81	$1.47	$44.74
Small	882	500	382	$17.50	$43.89	$33.53	$27.82	$6.02	$128.76
Medium	2,354	500	1,854	$17.50	$43.89	$162.75	$74.26	$16.05	$314.45
Large	4,820	500	4,320	$17.50	$43.89	$379.22	$152.06	$32.87	$625.54
XLg	6,690	500	6,190	$17.50	$43.89	$543.37	$211.05	$45.63	$861.44
AnnAvg	1,568	500	1,068	$17.50	$43.89	$93.75	$49.47	$10.69	$215.30
SGSAvg	1,886	500	1,386	$17.50	$43.89	$121.63	$59.48	$12.86	$255.36

	BILL IMPACTS PROPOSED RATES										
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill		
		500	>500		500	>500					
On-Peak	0.20			$27.00	$0.08185	$0.10185	$0.051660	$0.00000			
Off-Peak	0.80				$0.08185	$0.10185	$0.026750			$ Change	% Change
Xsm	216	216	0	$27.00	$17.68	$0.00	$6.87	$0.00	$51.55	$6.81	15.2%
Small	882	500	382	$27.00	$40.93	$38.91	$28.05	$0.00	$134.89	$6.13	4.8%
Medium	2,354	500	1,854	$27.00	$40.93	$188.83	$74.87	$0.00	$331.63	$17.18	5.5%
Large	4,820	500	4,320	$27.00	$40.93	$439.99	$153.30	$0.00	$661.22	$35.68	5.7%
XLg	6,690	500	6,190	$27.00	$40.93	$630.45	$212.77	$0.00	$911.15	$49.71	5.8%
AnnAvg	1,568	500	1,068	$27.00	$40.93	$108.78	$49.87	$0.00	$226.58	$11.28	5.2%
SGSAvg	1,886	500	1,386	$27.00	$40.93	$141.12	$59.97	$0.00	$269.02	$13.66	5.3%

SMALL GENERAL SERVICE DEMAND TIME OF USE

WINTER

BILL IMPACTS CURRENT GS-76 RATES

	Load Factor	kWh	Delivery (kWh) TIERS		kW	Delivery (kW)		Basic Service Charge	Delivery (Energy)		Delivery (Demand)		Base Fuel	PPFAC	Net Bill
			500	>500				$17.50	500	>500					
On-Peak		0.24							$0.08140	$0.08140			$0.032893	$0.00682	
Off-Peak		0.76							$0.06490	$0.06490			$0.027092		
Xsm	0.21	190	190	0	1.2			$17.50	$13.07	$0.00			$5.41	$1.30	$37.28
Small	0.29	687	500	187	3.2			$17.50	$34.40	$12.87			$19.55	$4.69	$89.01
Medium	0.37	1,744	500	1,244	6.5			$17.50	$34.40	$85.59			$49.64	$11.89	$199.02
Large	0.45	3,680	500	3,180	11.3			$17.50	$34.40	$218.78			$104.74	$25.10	$400.52
XLg	0.49	5,157	500	4,657	14.5			$17.50	$34.40	$320.40			$146.78	$35.17	$554.25
AnnAvg	0.36	1,568	500	1,068	6.0			$17.50	$34.40	$73.48			$44.63	$10.69	$180.70
SGSAvg	0.35	1,340	500	840	5.3			$17.50	$34.40	$57.79			$38.14	$9.14	$156.97

BILL IMPACTS PROPOSED RATES

	Load Factor	kWh	Delivery (kWh) TIERS		kW	Delivery (kW)		Basic Service Charge	Delivery (Energy)		Delivery (Demand)		Base Fuel	PPFAC	Net Bill		
			500	>500		7.0	> 7.0		500	>500	7.0	> 7.0					
On-Peak		0.24						$27.00	$0.04777	$0.04777	$9.60	$13.75	$0.033893	$0.00000			
Off-Peak		0.76							$0.04777	$0.04777			$0.028092			$ Change	% Change
Xsm	0.21	190	190	0	1.2	1.2	0.0	$27.00	$9.08	$0.00	$11.90	$0.00	$5.60	$0.00	$53.58	$16.30	43.7%
Small	0.29	687	500	187	3.2	3.2	0.0	$27.00	$23.89	$8.93	$31.01	$0.00	$20.24	$0.00	$111.07	$22.06	24.8%
Medium	0.37	1,744	500	1,244	6.5	6.5	0.0	$27.00	$23.89	$59.43	$62.11	$0.00	$51.38	$0.00	$223.81	$24.79	12.5%
Large	0.45	3,680	500	3,180	11.3	7.0	4.3	$27.00	$23.89	$151.91	$67.20	$58.85	$108.42	$0.00	$437.27	$36.75	9.2%
XLg	0.49	5,157	500	4,657	14.5	7.0	7.5	$27.00	$23.89	$222.46	$67.20	$103.26	$151.94	$0.00	$595.75	$41.50	7.5%
AnnAvg	0.36	1,568	500	1,068	6.0	6.0	0.0	$27.00	$23.89	$51.02	$57.41	$0.00	$46.20	$0.00	$205.52	$24.82	13.7%
SGSAvg	0.35	1,340	500	840	5.3	5.3	0.0	$27.00	$23.89	$40.13	$51.07	$0.00	$39.48	$0.00	$181.57	$24.60	15.7%

SMALL GENERAL SERVICE DEMAND TIME OF USE

SUMMER

BILL IMPACTS CURRENT GS-76 RATES

	Load Factor	kWh	Delivery (kWh) TIERS		kW	Delivery (kW)		Basic Service Charge	Delivery (Energy)		Delivery (Demand)		Base Fuel	PPFAC	Net Bill
			500	>500				$17.50	500	>500					
On-Peak		0.20							$0.09910	$0.09910			$0.050669	$0.00682	
Off-Peak		0.80							$0.08490	$0.08490			$0.026679		
Xsm	0.22	216	216	0	1.4			$17.50	$18.96	$0.00			$6.81	$1.47	$44.74
Small	0.31	882	500	382	3.9			$17.50	$43.89	$33.53			$27.82	$6.02	$128.76
Medium	0.40	2,354	500	1,854	8.1			$17.50	$43.89	$162.75			$74.26	$16.05	$314.45
Large	0.48	4,820	500	4,320	13.8			$17.50	$43.89	$379.22			$152.06	$32.87	$625.54
XLg	0.52	6,690	500	6,190	17.6			$17.50	$43.89	$543.37			$211.05	$45.63	$861.44
AnnAvg	0.36	1,568	500	1,068	6.0			$17.50	$43.89	$93.75			$49.47	$10.69	$215.30
SGSAvg	0.38	1,886	500	1,386	6.9			$17.50	$43.89	$121.63			$59.48	$12.86	$255.36

BILL IMPACTS PROPOSED RATES

	Load Factor	kWh	Delivery (kWh) TIERS		kW	Delivery (kW)		Basic Service Charge	Delivery (Energy)		Delivery (Demand)		Base Fuel	PPFAC	Net Bill		
			500	>500		7.0	> 7.0		500	>500	7.0	> 7.0					
On-Peak		0.20						$27.00	$0.05777	$0.05777	$9.60	$13.75	$0.05166	$0.00000			
Off-Peak		0.80							$0.05777	$0.05777			$0.026750			$ Change	% Change
Xsm	0.22	216	216	0	1.4	1.4	0.0	$27.00	$12.48	$0.00	$13.06	$0.00	$6.87	$0.00	$59.41	$14.67	32.8%
Small	0.31	882	500	382	3.9	3.9	0.0	$27.00	$28.89	$22.07	$37.34	$0.00	$28.05	$0.00	$143.35	$14.59	11.3%
Medium	0.40	2,354	500	1,854	8.1	7.0	1.1	$27.00	$28.89	$107.11	$67.20	$14.99	$74.87	$0.00	$320.06	$5.61	1.8%
Large	0.48	4,820	500	4,320	13.8	7.0	6.8	$27.00	$28.89	$249.57	$67.20	$93.36	$153.30	$0.00	$619.32	-$6.22	-1.0%
XLg	0.52	6,690	500	6,190	17.6	7.0	10.6	$27.00	$28.89	$357.60	$67.20	$145.89	$212.77	$0.00	$839.35	-$22.09	-2.6%
AnnAvg	0.36	1,568	500	1,068	6.0	6.0	0.0	$27.00	$28.89	$61.70	$57.41	$0.00	$49.87	$0.00	$224.87	$9.57	4.4%
SGSAvg	0.38	1,886	500	1,386	6.9	6.9	0.0	$27.00	$28.89	$80.05	$65.86	$0.00	$59.97	$0.00	$261.77	$6.41	2.5%

Medium General Service RATE MGS

WINTER

	BILL IMPACTS CURRENT RATES (GS-10)								
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill
		500	>500		500	>500			
				$15.50	$0.05700	$0.07900	$0.031532	$0.00682	
Xsm	9,000	500	8,500	$15.50	$28.50	$671.50	$283.79	$61.38	$1,060.67
Small	14,000	500	13,500	$15.50	$28.50	$1,066.50	$441.45	$95.48	$1,647.43
Medium	23,000	500	22,500	$15.50	$28.50	$1,777.50	$725.24	$156.86	$2,703.60
Large	37,000	500	36,500	$15.50	$28.50	$2,883.50	$1,166.68	$252.34	$4,346.52
XLg	45,000	500	44,500	$15.50	$28.50	$3,515.50	$1,418.94	$306.90	$5,285.34
AnnAvg	20,468	500	19,968	$15.50	$28.50	$1,577.50	$645.41	$139.59	$2,406.50
MGSAvg	17,563	500	17,063	$15.50	$28.50	$1,347.99	$553.80	$119.78	$2,065.57

	BILL IMPACTS PROPOSED RATES (MGS)									
	kW	kWh	Basic Service Charge	kW Charge	Delivery Charge kWh	Base Fuel	PPFAC	Net Bill		
			$40.00	$5.00	$0.07350	$0.032537	$0.00000			
Load Factor	35%								$ Change	% Change
Xsm	34	9,000	$40.00	$171.53	$661.50	$292.83	$0.00	$1,165.86	$105.19	9.9%
Small	53	14,000	$40.00	$266.82	$1,029.00	$455.52	$0.00	$1,791.34	$143.91	8.7%
Medium	88	23,000	$40.00	$438.35	$1,690.50	$748.35	$0.00	$2,917.20	$213.60	7.9%
Large	141	37,000	$40.00	$705.17	$2,719.50	$1,203.87	$0.00	$4,668.54	$322.02	7.4%
XLg	172	45,000	$40.00	$857.64	$3,307.50	$1,464.17	$0.00	$5,669.31	$383.97	7.3%
AnnAvg	78	20,468	$40.00	$390.10	$1,504.42	$665.98	$0.00	$2,600.50	$194.00	8.1%
MGSAvg	67	17,563	$40.00	$334.73	$1,290.90	$571.45	$0.00	$2,237.08	$171.51	8.3%

Medium General Service RATE MGS

SUMMER

	BILL IMPACTS CURRENT RATES (GS-10)								
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill
		500	>500		500	>500			
				$15.50	$0.07700	$0.09780	$0.035111	$0.00682	
Xsm	14,000	500	13,500	$15.50	$38.50	$1,320.30	$491.55	$95.48	$1,961.33
Small	19,000	500	18,500	$15.50	$38.50	$1,809.30	$667.11	$129.58	$2,659.99
Medium	32,000	500	31,500	$15.50	$38.50	$3,080.70	$1,123.55	$218.24	$4,476.49
Large	50,000	500	49,500	$15.50	$38.50	$4,841.10	$1,755.55	$341.00	$6,991.65
XLg	62,000	500	61,500	$15.50	$38.50	$6,014.70	$2,176.88	$422.84	$8,668.42
AnnAvg	20,468	500	19,968	$15.50	$38.50	$1,952.90	$718.66	$139.59	$2,865.15
MGSAvg	24,544	500	24,044	$15.50	$38.50	$2,351.53	$861.78	$167.39	$3,434.70

	BILL IMPACTS PROPOSED RATES (MGS)									
	kW	kWh	Basic Service Charge	kW Charge	Delivery Charge kWh	Base Fuel	PPFAC	Net Bill		
			$40.00	$7.00	$0.08450	$0.035868	$0.00000			
Load Factor	35%								$ Change	% Change
Xsm	53	14,000	$40.00	$373.55	$1,183.00	$502.15	$0.00	$2,098.70	$137.37	7.0%
Small	72	19,000	$40.00	$506.96	$1,605.50	$681.49	$0.00	$2,833.95	$173.96	6.5%
Medium	122	32,000	$40.00	$853.82	$2,704.00	$1,147.78	$0.00	$4,745.60	$269.11	6.0%
Large	191	50,000	$40.00	$1,334.10	$4,225.00	$1,793.40	$0.00	$7,392.50	$400.85	5.7%
XLg	236	62,000	$40.00	$1,654.28	$5,239.00	$2,223.82	$0.00	$9,157.10	$488.68	5.6%
AnnAvg	78	20,468	$40.00	$546.13	$1,729.57	$734.16	$0.00	$3,049.86	$184.71	6.4%
MGSAvg	94	24,544	$40.00	$654.89	$2,073.99	$880.36	$0.00	$3,649.24	$214.54	6.2%

MEDIUM GENERAL SERVICE TIME OF USE

Winter

	BILL IMPACTS CURRENT RATES (GS-76)							
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill
		500	>500					
On-Peak	0.24			$17.50	$0.08140	$0.032893	$0.00682	
Off-Peak	0.76				$0.06490	$0.027092		
Xsm	13,000	500	12,500	$17.50	$896.00	$370.58	$88.66	$1,372.74
Small	21,000	500	20,500	$17.50	$1,447.38	$598.63	$143.22	$2,206.73
Medium	29,000	500	28,500	$17.50	$1,998.77	$826.69	$197.78	$3,040.74
Large	39,000	500	38,500	$17.50	$2,688.00	$1,111.75	$265.98	$4,083.23
XLg	48,000	500	47,500	$17.50	$3,308.30	$1,368.31	$327.36	$5,021.47
AnnAvg	25,332	500	24,832	$17.50	$1,745.94	$722.12	$172.76	$2,658.32
MGSAvg	17,563	500	17,063	$17.50	$1,210.51	$500.66	$119.78	$1,848.45

	BILL IMPACTS PROPOSED RATES (MGS TOU)									
	kW	kWh	Basic Service Charge	Demand Charge	Delivery	Base Fuel	PPFAC	Net Bill		
Load Factor	63%									
On-Peak		0.24	$40.00	$4.00	$0.11580	$0.033893	$0.00000			
Off-Peak		0.76			$0.07310	$0.028092			$ Change	% Change
Xsm	28	13,000	$40.00	$110.56	$1,085.64	$383.58	$0.00	$1,619.78	$247.04	18.0%
Small	45	21,000	$40.00	$178.59	$1,753.73	$619.63	$0.00	$2,591.95	$385.22	17.5%
Medium	62	29,000	$40.00	$246.63	$2,421.82	$855.69	$0.00	$3,564.14	$523.40	17.2%
Large	83	39,000	$40.00	$331.67	$3,256.93	$1,150.75	$0.00	$4,779.35	$696.12	17.0%
XLg	102	48,000	$40.00	$408.21	$4,008.53	$1,416.31	$0.00	$5,873.05	$851.58	17.0%
AnnAvg	54	25,332	$40.00	$215.43	$2,115.48	$747.45	$0.00	$3,118.36	$460.04	17.3%
MGSAvg	37	17,563	$40.00	$149.36	$1,466.72	$518.23	$0.00	$2,174.31	$325.86	17.6%

MEDIUM GENERAL SERVICE TIME OF USE

Summer

	BILL IMPACTS CURRENT RATES (GS-76)							
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill
		500	>500					
On-Peak	0.20			$17.50	$0.09910	$0.050669	$0.00682	
Off-Peak	0.80				$0.08490	$0.026679		
Xsm	18,000	500	17,500	$17.50	$1,580.16	$568.01	$122.76	$2,288.43
Small	27,000	500	26,500	$17.50	$2,370.24	$852.01	$184.14	$3,423.89
Medium	37,000	500	36,500	$17.50	$3,248.11	$1,167.57	$252.34	$4,685.52
Large	50,000	500	49,500	$17.50	$4,389.34	$1,577.80	$341.00	$6,325.64
XLg	65,000	500	64,500	$17.50	$5,706.14	$2,051.14	$443.30	$8,218.08
AnnAvg	25,332	500	24,832	$17.50	$2,223.79	$799.37	$172.76	$3,213.42
MGSAvg	24,544	500	24,044	$17.50	$2,154.67	$774.52	$167.39	$3,114.08

	BILL IMPACTS PROPOSED RATES (MGS TOU)									
	kW	kWh	Basic Service Charge	Demand Charge	Delivery	Base Fuel	PPFAC	Net Bill		
Load Factor	63%									
On-Peak		0.20	$40.00	$8.00	$0.11580	$0.051660	$0.00000			
Off-Peak		0.80			$0.07310	$0.026750			$ Change	% Change
Xsm	38	18,000	$40.00	$306.16	$1,472.05	$572.65	$0.00	$2,390.86	$102.43	4.5%
Small	57	27,000	$40.00	$459.23	$2,208.07	$858.98	$0.00	$3,566.28	$142.39	4.2%
Medium	79	37,000	$40.00	$629.32	$3,025.88	$1,177.12	$0.00	$4,872.32	$186.80	4.0%
Large	106	50,000	$40.00	$850.43	$4,089.03	$1,590.70	$0.00	$6,570.16	$244.52	3.9%
XLg	138	65,000	$40.00	$1,105.56	$5,315.74	$2,067.91	$0.00	$8,529.21	$311.13	3.8%
AnnAvg	54	25,332	$40.00	$430.86	$2,071.64	$805.90	$0.00	$3,348.40	$134.98	4.2%
MGSAvg	52	24,544	$40.00	$417.47	$2,007.25	$780.85	$0.00	$3,245.57	$131.49	4.2%

Large General Service Rate LGS-13

WINTER

	BILL IMPACTS CURRENT RATES								
	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill
				$775.00	$15.25	$0.01340	$0.031532	$0.00682	
Xsm	0.55	200	58,000	$775.00	$3,050.00	$777.20	$1,828.86	$395.56	$6,826.62
Small	0.55	223	91,360	$775.00	$3,404.79	$1,224.22	$2,880.76	$623.08	$8,907.85
Medium	0.55	427	174,840	$775.00	$6,515.91	$2,342.86	$5,513.05	$1,192.41	$16,339.23
Large	0.55	725	296,700	$775.00	$11,057.37	$3,975.78	$9,355.54	$2,023.49	$27,187.18
XLg	0.55	1088	445,200	$775.00	$16,591.64	$5,965.68	$14,038.05	$3,036.26	$40,406.63
AnnAvg	0.55	395	161,792	$775.00	$6,029.62	$2,168.01	$5,101.61	$1,103.42	$15,177.66
LGSAvg	0.55	366	149,663	$775.00	$5,577.62	$2,005.48	$4,719.17	$1,020.70	$14,097.97

	BILL IMPACTS PROPOSED RATES										
	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill		
				$950.00	$17.55	$0.01730	$0.032537	$0.00000			
										$ Change	% Change
Xsm	0.55	200	58,000	$950.00	$3,510.00	$1,003.40	$1,887.15	$0.00	$7,350.55	$523.93	7.7%
Small	0.55	223	91,360	$950.00	$3,918.30	$1,580.53	$2,972.58	$0.00	$9,421.41	$513.56	5.8%
Medium	0.55	427	174,840	$950.00	$7,498.64	$3,024.73	$5,688.77	$0.00	$17,162.14	$822.91	5.0%
Large	0.55	725	296,700	$950.00	$12,725.04	$5,132.91	$9,653.73	$0.00	$28,461.68	$1,274.50	4.7%
XLg	0.55	1,088	445,200	$950.00	$19,093.99	$7,701.96	$14,485.47	$0.00	$42,231.42	$1,824.79	4.5%
AnnAvg	0.55	395	161,792	$950.00	$6,939.01	$2,798.99	$5,264.21	$0.00	$15,952.21	$774.55	5.1%
LGSAvg	0.55	366	149,663	$950.00	$6,418.83	$2,589.17	$4,869.59	$0.00	$14,827.59	$729.62	5.2%

Large General Service Rate LGS-13

SUMMER

	BILL IMPACTS CURRENT RATES								
	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill
				$775.00	$15.25	$0.01920	$0.035111	$0.00682	
Xsm	0.55	200	72,960	$775.00	$3,050.00	$1,400.83	$2,561.70	$497.59	$8,285.12
Small	0.55	282	115,584	$775.00	$4,307.57	$2,219.21	$4,058.27	$788.28	$12,148.33
Medium	0.55	521	213,300	$775.00	$7,949.23	$4,095.36	$7,489.18	$1,454.71	$21,763.48
Large	0.55	815	333,600	$775.00	$12,432.55	$6,405.12	$11,713.03	$2,275.15	$33,600.85
XLg	0.55	1230	503,200	$775.00	$18,753.18	$9,661.44	$17,667.86	$3,431.82	$50,289.30
AnnAvg	0.55	395	161,792	$775.00	$6,029.62	$3,106.40	$5,680.66	$1,103.42	$16,695.10
LGSAvg	0.55	437	178,619	$775.00	$6,656.74	$3,429.48	$6,271.49	$1,218.18	$18,350.89

	BILL IMPACTS PROPOSED RATES										
	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill		
				$950.00	$17.55	$0.02280	$0.035868	$0.00000			
										$ Change	% Change
Xsm	0.55	200	72,960	$950.00	$3,510.00	$1,663.49	$2,616.93	$0.00	$8,740.42	$455.30	5.5%
Small	0.55	282	115,584	$950.00	$4,957.23	$2,635.32	$4,145.77	$0.00	$12,688.32	$539.99	4.4%
Medium	0.55	521	213,300	$950.00	$9,148.13	$4,863.24	$7,650.64	$0.00	$22,612.01	$848.53	3.9%
Large	0.55	815	333,600	$950.00	$14,307.62	$7,606.08	$11,965.56	$0.00	$34,829.26	$1,228.41	3.7%
XLg	0.55	1,230	503,200	$950.00	$21,581.52	$11,472.96	$18,048.78	$0.00	$52,053.26	$1,763.96	3.5%
AnnAvg	0.55	395	161,792	$950.00	$6,939.01	$3,688.85	$5,803.14	$0.00	$17,381.00	$685.90	4.1%
LGSAvg	0.55	437	178,619	$950.00	$7,660.70	$4,072.51	$6,406.70	$0.00	$19,089.91	$739.02	4.0%

Large General Service Time of Use Rate LGS-85

WINTER

	BILL IMPACTS CURRENT RATES								
	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill
	On-Peak		24.3%	$950.00	$11.59	$0.00300	$0.032893	$0.00682	
	Off-Peak		75.7%		$9.10	$0.00050	$0.027092		
Xsm	0.58	288	124,480	$950.00	$5,443.40	$137.85	$3,547.85	$848.95	$10,928.05
Small	0.58	390	168,111	$950.00	$7,351.33	$186.16	$4,791.38	$1,146.51	$14,425.38
Medium	0.58	476	205,552	$950.00	$8,988.61	$227.63	$5,858.52	$1,401.86	$17,426.62
Large	0.58	621	267,929	$950.00	$11,716.31	$296.70	$7,636.35	$1,827.28	$22,426.64
XLg	0.58	827	356,983	$950.00	$15,610.54	$395.32	$10,174.50	$2,434.62	$29,564.98
AnnAvg	0.58	448	193,169	$950.00	$8,447.12	$213.91	$5,505.59	$1,317.41	$16,434.03
LGSAvg	0.58	347	149,663	$950.00	$6,544.64	$165.74	$4,265.60	$1,020.70	$12,946.68

	BILL IMPACTS PROPOSED RATES										
	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill		
	On-Peak		24.3%	$950.00	$18.50	$0.00710	$0.033893	$0.00000			
	Off-Peak		75.7%			$0.00125	$0.028092			$ Change	% Change
Xsm	0.58	288	124,480	$950.00	$5,336.67	$332.52	$3,672.33	$0.00	$10,291.52	-$636.53	-5.8%
Small	0.58	390	168,111	$950.00	$7,207.18	$449.07	$4,959.49	$0.00	$13,565.74	-$859.64	-6.0%
Medium	0.58	476	205,552	$950.00	$8,812.37	$549.09	$6,064.07	$0.00	$16,375.53	-$1,051.09	-6.0%
Large	0.58	621	267,929	$950.00	$11,486.57	$715.72	$7,904.28	$0.00	$21,056.57	-$1,370.07	-6.1%
XLg	0.58	827	356,983	$950.00	$15,304.45	$953.60	$10,531.48	$0.00	$27,739.53	-$1,825.45	-6.2%
AnnAvg	0.58	448	193,169	$950.00	$8,281.49	$516.01	$5,698.76	$0.00	$15,446.26	-$987.77	-6.0%
LGSAvg	0.58	347	149,663	$950.00	$6,416.31	$399.79	$4,415.27	$0.00	$12,181.37	-$765.31	-5.9%

Large General Service Time of Use Rate LGS-85

SUMMER

	BILL IMPACTS CURRENT RATES								
	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill
	On-Peak		19.7%	$950.00	$14.55	$0.00860	$0.050669	$0.00682	
	Off-Peak		80.3%		$10.92	$0.00600	$0.026679		
Xsm	0.58	317	136,680	$950.00	$7,375.63	$890.15	$4,293.00	$932.16	$14,440.94
Small	0.58	436	188,009	$950.00	$10,145.48	$1,224.44	$5,905.20	$1,282.22	$19,507.34
Medium	0.58	536	231,233	$950.00	$12,477.97	$1,505.94	$7,262.82	$1,577.01	$23,773.74
Large	0.58	736	317,688	$950.00	$17,143.31	$2,068.99	$9,978.30	$2,166.63	$32,307.23
XLg	0.58	976	420,961	$950.00	$22,716.21	$2,741.57	$13,222.01	$2,870.95	$42,500.74
AnnAvg	0.58	448	193,169	$950.00	$10,423.93	$1,258.04	$6,067.27	$1,317.41	$20,016.65
LGSAvg	0.58	414	178,619	$950.00	$9,638.76	$1,163.28	$5,610.26	$1,218.18	$18,580.48

	BILL IMPACTS PROPOSED RATES										
	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill		
	On-Peak		19.7%	$950.00	$22.15	$0.01854	$0.051660	$0.00000			
	Off-Peak		80.3%			$0.01270	$0.026750			$ Change	% Change
Xsm	0.58	317	136,680	$950.00	$7,015.81	$1,893.22	$4,327.50	$0.00	$14,186.53	-$254.41	-1.8%
Small	0.58	436	188,009	$950.00	$9,650.54	$2,604.20	$5,952.65	$0.00	$19,157.39	-$349.95	-1.8%
Medium	0.58	536	231,233	$950.00	$11,869.23	$3,202.92	$7,321.19	$0.00	$23,343.34	-$430.40	-1.8%
Large	0.58	736	317,688	$950.00	$16,306.98	$4,400.45	$10,058.48	$0.00	$31,715.91	-$591.32	-1.8%
XLg	0.58	976	420,961	$950.00	$21,608.00	$5,830.93	$13,328.26	$0.00	$41,717.19	-$783.55	-1.8%
AnnAvg	0.58	448	193,169	$950.00	$9,915.41	$2,675.68	$6,116.03	$0.00	$19,657.12	-$359.53	-1.8%
LGSAvg	0.58	414	178,619	$950.00	$9,168.54	$2,474.13	$5,655.34	$0.00	$18,248.01	-$332.47	-1.8%

Large Power Service Rate LPS-90

WINTER

	BILL IMPACTS CURRENT RATES								
	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill
	On-Peak		23.1%	$2,000.00	$15.49	$0.00750	$0.029581	$0.00682	
	Off-Peak		76.9%			$0.00710	$0.024352		
Xsm	0.80	4,460	2,654,563	$2,000.00	$69,084.65	$19,092.82	$67,852.15	$18,104.12	$176,133.74
Small	0.80	7,130	4,243,957	$2,000.00	$110,448.41	$30,524.46	$108,477.97	$28,943.79	$280,394.63
Medium	0.80	13,369	7,957,222	$2,000.00	$207,085.63	$57,231.93	$203,391.15	$54,268.25	$523,976.96
Large	0.80	16,093	9,578,605	$2,000.00	$249,281.91	$68,893.65	$244,834.63	$65,326.09	$630,336.28
XLg	0.80	17,404	10,359,070	$2,000.00	$269,593.40	$74,507.11	$264,783.76	$70,648.86	$681,533.13
AnnAvg	0.80	9,398	5,593,406	$2,000.00	$145,567.63	$40,230.30	$142,970.65	$38,147.03	$368,915.61
LPSAvg	0.80	8,725	5,193,148	$2,000.00	$135,150.99	$37,351.47	$132,739.84	$35,417.27	$342,659.57

	BILL IMPACTS PROPOSED RATES										
	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill		
	On-Peak		23.1%	$10,000.00	$16.55	$0.00780	$0.032198	$0.00000			
	Off-Peak		76.9%			$0.00780	$0.026687			$ Change	% Change
Xsm	0.80	4,460	2,654,563	$10,000.00	$73,812.19	$20,705.59	$74,223.57	$0.00	$178,741.35	$2,607.61	1.5%
Small	0.80	7,130	4,243,957	$10,000.00	$118,006.53	$33,102.86	$118,664.22	$0.00	$279,773.61	-$621.02	-0.2%
Medium	0.80	13,369	7,957,222	$10,000.00	$221,256.76	$62,066.33	$222,489.90	$0.00	$515,812.99	-$8,163.97	-1.6%
Large	0.80	16,093	9,578,605	$10,000.00	$266,340.58	$74,713.12	$267,824.99	$0.00	$618,878.69	-$11,457.59	-1.8%
XLg	0.80	17,404	10,359,070	$10,000.00	$288,042.02	$80,800.75	$289,647.38	$0.00	$668,490.15	-$13,042.98	-1.9%
AnnAvg	0.80	9,398	5,593,406	$10,000.00	$155,529.01	$43,628.56	$156,395.82	$0.00	$365,553.39	-$3,362.22	-0.9%
LPSAvg	0.80	8,725	5,193,148	$10,000.00	$144,399.54	$40,506.56	$145,204.33	$0.00	$340,110.43	-$2,549.14	-0.7%

Large Power Service Rate LPS-90

Summer

	BILL IMPACTS CURRENT RATES								
	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill
	On-Peak		17.0%	$2,000.00	$20.49	$0.00690	$0.045568	$0.00682	
	Off-Peak		83.0%			$0.00650	$0.023985		
Xsm	0.80	4527	2,694,604	$2,000.00	$92,762.83	$17,698.42	$74,530.92	$18,377.20	$205,369.37
Small	0.80	8371	4,982,527	$2,000.00	$171,525.50	$32,725.72	$137,813.33	$33,980.83	$378,045.38
Medium	0.80	14825	8,823,900	$2,000.00	$303,766.32	$57,956.23	$244,063.10	$60,179.00	$667,964.65
Large	0.80	19858	11,819,577	$2,000.00	$406,893.70	$77,632.12	$326,921.50	$80,609.52	$894,056.84
XLg	0.80	21021	12,511,438	$2,000.00	$430,711.30	$82,176.33	$346,057.91	$85,328.01	$946,273.55
AnnAvg	0.80	9398	5,593,406	$2,000.00	$192,555.25	$36,738.03	$154,709.82	$38,147.03	$424,150.13
LPSAvg	0.80	10375	6,174,912	$2,000.00	$212,573.82	$40,557.42	$170,793.88	$42,112.90	$468,038.02

	BILL IMPACTS PROPOSED RATES										
	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill		
	On-Peak		17.0%	$10,000.00	$21.00	$0.00780	$0.049077	$0.00000			
	Off-Peak		83.0%			$0.00780	$0.025413			$ Change	% Change
Xsm	0.80	4,527	2,694,604	$10,000.00	$95,071.71	$21,017.91	$79,333.44	$0.00	$205,423.06	$53.69	0.0%
Small	0.80	8,371	4,982,527	$10,000.00	$175,794.80	$38,863.71	$146,693.55	$0.00	$371,352.06	-$6,693.32	-1.8%
Medium	0.80	14,825	8,823,900	$10,000.00	$311,327.12	$68,826.42	$259,789.70	$0.00	$649,943.24	-$18,021.41	-2.7%
Large	0.80	19,858	11,819,577	$10,000.00	$417,021.37	$92,192.70	$347,987.21	$0.00	$867,201.28	-$26,855.56	-3.0%
XLg	0.80	21,021	12,511,438	$10,000.00	$441,431.78	$97,589.22	$368,356.70	$0.00	$917,377.70	-$28,895.85	-3.1%
AnnAvg	0.80	9,398	5,593,406	$10,000.00	$197,347.98	$43,628.56	$164,678.79	$0.00	$415,655.33	-$8,494.80	-2.0%
LPSAvg	0.80	10,375	6,174,912	$10,000.00	$217,864.83	$48,164.31	$181,799.25	$0.00	$457,828.39	-$10,209.63	-2.2%

Traffic Signal & Street Lighting

WINTER

	BILL IMPACTS CURRENT RATES					
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill
			$0.04760	$0.031532	$0.00682	
Xsm	169		$8.04	$5.33	$1.15	$14.52
Small	1,180		$56.17	$37.21	$8.05	$101.43
Medium	4,370		$208.01	$137.79	$29.80	$375.60
Large	7,560		$359.86	$238.38	$51.56	$649.80
XLg	9,300		$442.68	$293.25	$63.43	$799.36
AnnAvg	2,484		$118.25	$78.33	$16.94	$213.52
TSSLAvg	2,687		$127.89	$84.72	$18.32	$230.93

	BILL IMPACTS PROPOSED RATES							
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill		
			$0.06510	$0.032537	$0.00000			
							$ Change	% Change
Xsm	169		$11.00	$5.50	$0.00	$16.50	$1.98	13.6%
Small	1,180		$76.82	$38.39	$0.00	$115.21	$13.78	13.6%
Medium	4,370		$284.49	$142.19	$0.00	$426.68	$51.08	13.6%
Large	7,560		$492.16	$245.98	$0.00	$738.14	$88.34	13.6%
XLg	9,300		$605.43	$302.59	$0.00	$908.02	$108.66	13.6%
AnnAvg	2,484		$161.72	$80.83	$0.00	$242.55	$29.03	13.6%
TSSLAvg	2,687		$174.90	$87.42	$0.00	$262.32	$31.39	13.6%

Traffic Signal & Street Lighting

Summer

	BILL IMPACTS CURRENT RATES					
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill
			$0.04760	$0.035111	$0.00682	
Xsm	170		$8.09	$5.97	$1.16	$15.22
Small	1,020		$48.55	$35.81	$6.96	$91.32
Medium	3,599		$171.31	$126.36	$24.55	$322.22
Large	6,200		$295.12	$217.69	$42.28	$555.09
XLg	7,500		$357.00	$263.33	$51.15	$671.48
AnnAvg	2,484		$118.25	$87.22	$16.94	$222.41
TSSLAvg	2,204		$104.93	$77.40	$15.03	$197.36

	BILL IMPACTS PROPOSED RATES							
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill		
			$0.06510	$0.035868	$0.00000			
							$ Change	% Change
Xsm	170		$11.07	$6.10	$0.00	$17.17	$1.95	12.8%
Small	1,020		$66.40	$36.59	$0.00	$102.99	$11.67	12.8%
Medium	3,599		$234.29	$129.09	$0.00	$363.38	$41.16	12.8%
Large	6,200		$403.62	$222.38	$0.00	$626.00	$70.91	12.8%
XLg	7,500		$488.25	$269.01	$0.00	$757.26	$85.78	12.8%
AnnAvg	2,484		$161.72	$89.10	$0.00	$250.82	$28.41	12.8%
TSSLAvg	2,204		$143.51	$79.07	$0.00	$222.58	$25.22	12.8%

Area Lighting

	BILL IMPACTS CURRENT RATES				
	kWh	Delivery	Base Fuel	PPFAC	Net Bill
				$0.00682	
Xsm	93	$8.19	$0.85	$0.63	$9.67
Small	124	$23.72	$0.94	$0.85	$25.51
Medium	215	$23.72	$1.34	$1.47	$26.53
Large	720	$12.29	$3.36	$4.91	$20.56
XLg	1,339	$18.70	$5.38	$9.13	$33.21
Pole	0	$2.86	$0.00	$0.00	$2.86
ALAvg	316	$8.19	$1.34	$2.15	$11.68

	BILL IMPACTS PROPOSED RATES						
	kWh	Delivery	Base Fuel	PPFAC	Net Bill		
				$0.00000			
						$ Change	% Change
Xsm	93	$11.95	$0.87	$0.00	$12.82	$3.15	32.6%
Small	124	$34.60	$0.96	$0.00	$35.56	$10.05	39.4%
Medium	215	$34.60	$1.37	$0.00	$35.97	$9.44	35.6%
Large	720	$17.92	$3.42	$0.00	$21.34	$0.78	3.8%
XLg	1,339	$27.29	$5.30	$0.00	$32.59	-$0.62	-1.9%
Pole	0	$4.17	$0.00	$0.00	$4.17	$1.31	45.8%
ALAvg	316	$11.95	$1.37	$0.00	$13.32	$1.64	14.0%

Exhibit CAJ – R – 4

Tucson Electric Power
Lifeline Rate Consolidation and Proposed Discounts
Test Year Ending June 30, 2015

No. Schedules	Cust. Count	Tariff Status	Tariff Description	Proposed Flat Discount
1	7,673	Open	**Residential Service**	
	880	Closed	*Frozen - R-05-01F Lifeline % Discount	$15.00
	4,640	Closed	*Frozen - R-06-01 Lifeline (Flat) Discount	$15.00
	3	Closed	*Frozen R-06-01Q - Residential Electric Net Metering	$15.00
	9	Closed	*Frozen - R-06-01 Ilfeline Bright Community Solar	$15.00
	364	Closed	*Frozen - R-04-01F Senior % Discount	**$31.00**
	523	Closed	*Frozen - R-08-01 Medical Discount Rate	**$40.00**
2	106	Open	**Residential Service Time of Use**	
	1	Closed	*Frozen - R-05-21F Lifeline % Discount	$15.00
	7	Closed	*Frozen - R-05-70F Lifeline % Discount	$15.00
	50	Closed	*Frozen - R-06-70 Lifeline (Flat) Discount	$15.00
	2	Closed	*Frozen - R-04-21F Senior % Discount	$31.00
	14	Closed	*Frozen - R-06-21F Lifeline (Flat) Discount	$31.00
	1	Closed	*Frozen R-06-21F Lifeline (Flat) Discount Net Metering	$31.00
	4	Closed	*Frozen - R-04-70F Senior % Discount	$31.00
	6	Closed	*Frozen - R-08-21F Medical Discount	**$40.00**
	15	Closed	*Frozen - R-08-70 Medical Discount	**$40.00**
3	7	**Open**	**Residential Service Time of Use Super Peak**	
4	230	**Open**	**Special Residential Electric Service**	
	241	Closed	*Frozen - R-06-201A Lifeline (Flat) Discount	$15.00
	11	Closed	*Frozen - R-08-201A Medical Discount	**$31.00**
5	4	**Open**	**Special Residential Electric Service Time Of Use**	
	4	Closed	*Frozen - R-06-201B Lifeline (Flat) Discount	$15.00

Rebuttal Testimony of

Richard D. Bachmeier

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-1933A-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

Rebuttal Testimony of

Richard D. Bachmeier

on Behalf of

Tucson Electric Power Company

July 25, 2016

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EXHIBITS:

Exhibit RDB-R-1 Original Tables from Direct Testimony of Dallas Dukes
Exhibit RDB-R-2 Revised Tables from Direct Testimony of Dallas Dukes
Exhibit RDB-R-3 SOLON Corporation Response to TEP DR 2.02
Exhibit RDB-R-4 Screen Shot for Residential Customer Sample Size Calculation
Exhibit RDB-R-5 TEP Responses to SOLON DR 3.1 and SOLON DR 3.2

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Richard D. Bachmeier and my business address is 88 East Broadway Blvd., Tucson, Arizona 85701.

Q. By whom are you employed and what are your duties and responsibilities?

A. I am a Principal Rate Designer for Tucson Electric Power Company ("TEP" or the "Company"). My responsibilities include developing rates, charges, and terms of service for TEP and UNS Electric rate offerings, performing cost of service analyses, and providing general rate and pricing support for existing and new programs.

Q. Please describe your background and work experience.

A. I hold Bachelor of Science degrees in Economics and Mathematics from the University of North Dakota and a Master of Applied Geography with a major in Resource and Environmental Studies from Texas State University. I also completed all coursework and examination requirements for the Ph.D. in Economics at the University of Texas at Austin. I have worked for over 30 years in the energy industry and have experience with both regulated utilities and competitive markets. The majority of my professional experience in the electric industry has been in the areas of utility regulation and ratemaking, utility resource planning, competitive energy markets, and environmental policy. I have testified in regulatory and legislative proceedings in Texas and Florida.

I began employment with TEP in December 2014. Prior to joining TEP, I was employed by Gainesville Regional Utilities (GRU), a municipal utility in Gainesville, Florida, for approximately seven and one-half years. For the majority of my employment at GRU, I was the Electric System Planning Director responsible for oversight of the utility's long-term production cost modeling, negotiating and structuring wholesale power contracts,

electric resource planning, and coordination of GRU's NERC Compliance Program. For my last two years at GRU I held the title of Electric Reliability Compliance Officer and was responsible for the oversight of the GRU NERC Compliance Program on a full time basis. Before my employment at GRU, I was employed by Orlando Utilities Commission (OUC), a municipal utility in Orlando, Florida, for approximately four and one-half years as a Senior Retail Pricing Coordinator and Planning Analyst.

Prior to working at OUC, I was employed for one year at TXU Energy in Dallas, Texas, four years at Enron Corporation in Houston, Texas, and twelve years at the Public Utility Commission of Texas (PUCT) in Austin, Texas. While at the PUCT, I held various positions working in the areas of utility rate design, forecasting, resource planning, environmental externalities, and non-traditional utility industry pricing. I finished my tenure at the PUCT as Assistant Director of the Competitive Issues Division with responsibility for supervising the implementation of the Commission's policies applicable to competitive and non-traditional pricing in the electric and telecommunications industries. Prior to my employment at the PUCT, I spent four years as an Instructor in the Economics Department at the University of Texas at Austin and was responsible for all duties associated with teaching introductory microeconomics and macroeconomics courses.

Q. Did you file Direct Testimony in this proceeding?

A. No, I did not.

Q. What issues do you address in your Rebuttal Testimony?

A. In response to the Commission Staff ("Staff") and Intervenor rate design testimony, I discuss (1) TEP's approach to the development and design of the Company's proposed

three-part rates for residential and Small General Service ("SGS")[1] customers, (2) TEP's analyses of the likely customer bill impacts expected from the Company's proposed three-part rates and changes to net metering ("NEM") for residential and SGS customers, and (3) Staff and Intervenor comments in their Direct Testimony on TEP's approach to developing and analyzing the Company's proposed new three-part rates and changes to NEM.

Any omission in my Rebuttal Testimony of other positions taken by Staff and Intervenors in their testimonies should not be interpreted as agreement or support of their positions and I reserve the right to address those issues as they arise during the remainder of this proceeding.

Q. Why does the Company feel it necessary to address its approach to analyzing its three-part rate and NEM proposals at this time?

A. Some parties in their rate design testimony have criticized the Company's analyses of these proposals. Some of the criticisms may stem from a misunderstanding of the analyses the Company actually performed in addressing these issues and some appear to be little more than a purposeful distraction. Laying out the Company's approach in detail at this time is intended to clear up some of the misunderstanding and address any unwarranted criticism.

Q. Which parties' testimonies do you address in your Rebuttal Testimony?

A. I will be addressing the rate design Direct Testimonies of Staff, SOLON Corporation ("SOLON"), the Vote Solar Initiative ("Vote Solar"), the Energy Freedom Coalition of America ("EFCA"), and Residential Utility Consumers Office ("RUCO") as they relate to the issues identified above.

[1] These customers currently take service under the TEP GS-10 rate tariff. The Company is proposing to rename the class Small General Service ("SGS") in this proceeding.

Q. How is your Rebuttal Testimony organized?

A. The remainder of my testimony is organized as follows.

II. TEP's Approach to Analyzing Proposed Three-Part Rates and Net Metering Changes.

III. TEP's Rebuttal Proposals for Residential and SGS Three-Part Rates.

IV. Response to Staff's Testimony.

V. Response to SOLON's Testimony.

VI. Response to Vote Solar's Testimony.

VII. Response to EFCA's Testimony.

VIII. Response to RUCO's Testimony.

II. TEP'S APPROACH TO ANALYZING PROPOSED THREE-PART RATES AND CHANGES TO NET METERING.

Q. Please briefly summarize the Company's initial proposals regarding three-part rates for residential and SGS customers and changes to net metering in this proceeding.

A. The Company, in its Direct Testimony, proposed (1) mandatory three-part rates for all partial requirement residential and SGS customers who installed distributed generation ("DG") after June 1, 2015 (collectively, "New DG Customers"), (2) optional three-part rates for all other residential and small general service customers, and (3) revisions to the Company's Net Metering rider (proposed Rider 15) applicable to new DG customers to eliminate any banking of excess kWh generation by DG customers and instead pay out a credit based on the amount of excess kWh generation.

Q. Please describe the Company's initial proposal for the residential three-part rates.

A. In Direct Testimony the Company initially proposed three-part basic residential ("RES-D") and residential time-of-use ("RES TOU-D") non-fuel rates with the following

charges:

- A monthly Basic Service Charge of $20.
- Demand charges based on the maximum one-hour average kW during the billing month of $7.40/kW for the first 7 kW of billing demand and $11.90/kW for all billing demand greater than 7 kW.
- An Energy Delivery Charge of $0.025/kWh for all billing kWh.
- All other charges equal to those in the Company's equivalent two-part tariff for basic residential and residential TOU service.

The Company has submitted draft tariffs for these rate options as RES-D and RES TOU-D, respectively, as Exhibits CAJ-3 (clean) and CAJ-4 (redlined) to the Direct Testimony of Company witness Mr. Craig Jones.

Q. Please describe the Company's initial proposal for the SGS three-part rates.

A. In Direct Testimony the Company initially proposed three-part basic SGS-D and SGS TOU-D TOU non-fuel rates with the following charges:

- A monthly Basic Service Charge of $30.
- Demand charges based on the maximum one-hour average kW during the billing month of $9.95/kW for the first 7 kW of billing demand and $13.90/kW for all billing demand greater than 7 kW.
- Energy Delivery Charges of $0.0575/kWh for all summer billing kWh and $0.0475/kWh for all winter billing kWh.
- All other charges equal to those in the Company's equivalent two-part tariff for basic small general service and small general service TOU.

The Company has submitted draft tariffs for these rate options as SGS-D and SGS TOU-D, respectively, as Exhibit Nos. CAJ-3 (clean) and CAJ-4 (redlined) to the Direct Testimony of Company witness Mr. Jones.

Q. How did the Company approach designing the proposed three-part rates for residential customers in its Application?

A. First, the Company drew a random sample of hourly load shapes for 14,346 TEP full requirements residential customers for the period from July 2013 through June 2015. The sample was tested to assure that it was sufficiently representative of the population from which it was drawn. We deleted 160 observations for customers who averaged less than 5 kWh per month of usage during the test year. That left a sample size of 14,186 residential customer observations. Using SAS statistical software, TEP calculated monthly total, on-peak, and off-peak values for each observation from the hourly load shapes for the following variables:

- Energy consumption (kWh)
- Maximum demand (kW)

Q. Why did the Company use SAS to convert hourly loads into monthly values?

A. The hourly customer sample was too large to efficiently manipulate in Excel.

Q. How did the Company approach analyzing the impacts of its proposed changes to net metering on new residential DG customers?

A. TEP used the National Renewable Energy Laboratory System Advisor Model ("NREL" and "SAM") version 2016.3.14 to develop a typical hourly photovoltaic ("PV") system output profile for a residential DG customer in the Tucson area. To generate the PV output profiles, the Company assumed a 20% tilt roof-mount 4.0 kWdc PV system with a rated inverter size of 3.64 kWdc. PV system output profiles were developed for both south and west facing systems. Once the base PV output profiles were generated from NREL SAM, TEP assumed that each DG customer's system would be sized to offset

100% of annual usage[2] and using the NREL SAM output, SAS, and the same sample data, TEP calculated monthly total, on-peak, and off-peak values for the following variables:

- Total PV output (kWh)
- Net energy delivered by TEP to a DG customer (kWh)
- Net exports of energy produced by a DG customer (kWh or "kbh")

Q. What did TEP do with the monthly values developed from the sample hourly profiles?

A. TEP transferred the monthly values calculated from the sample with SAS to Excel and subdivided the entire sample into groups, or bins, ranked by monthly kWh usage, each containing five percent of the sample. In other words, the first bin contained observations for monthly kWh usage corresponding to the fifth percentile, the second corresponding to the tenth percentile, and so on. Percentile groupings were also added for the 98th, 99th, and 100th percentiles to give some information on customer characteristics at the higher end of the sample distribution. The monthly usages for each of the percentile groupings were then matched to the other variables in the data set. For example, the monthly kW demands for the 50th percentile bin are calculated as the average kW demands for observations corresponding to the monthly kWh groupings in that bin. TEP developed percentile groupings in this manner for all of the variables described above.

Q. Did TEP use this sample data for any other purpose?

A. Yes. TEP used the sample data to develop two other important inputs to the analyses. First, TEP used the sample of residential customer hourly load profiles to develop average hourly load shapes for the mean and maximum of the sample as well as several

[2] Although TEP assumed to use 100% PV offset of annual usage in this step, the model discussed later in this section allows the user to choose any level.

chosen percentiles. The only purpose for which TEP used these average load profiles was to identify the time of the hourly peak demand for each month so we could analyze any possible peak shifting due to PV and determine where billing demands should be adjusted for PV output. The average load shapes in no way entered into calculating the net kWh delivered to the customer or net exports from the PV system. The reasons for not using these average load shapes for these purposes are well known to load research professionals and I will expand on this later in my testimony.

Second, the data were used to assign average monthly load factors to customers at varying levels of monthly kWh usage for bill impact analysis. With a strictly volumetric rate, the customer's load factor is irrelevant to the bill calculation because there is no kW billing component. However, once a demand charge is introduced, billing kW for the "typical" customer sizes used in the bill comparisons must be estimated and assigned. TEP used the monthly data described above and created groups corresponding to customer monthly kWh usage beginning with 100 kWh per month up to 4,500 per month in increments of 100 kWh. This yielded 45 groups and average kW demands were assigned to each of these kWh levels. The kW demands for each usage level was calculated as the sample average kW for usage levels between the midpoints of the kWh groupings. This yielded a load factor for each kWh group. TEP then used the LINEST function in Excel to estimate the parameters of a power regression to best fit the relationship. These estimated regression parameters were used later to assign load factors to usage levels for bill impact analysis.

Q. How did TEP approach analyzing the SGS rate class?

A. The Company used exactly the same methodology described above, but with a random sample of 5,550 TEP SGS customers.

Q. Did TEP make these analyses available to all parties?

A. Yes. TEP submitted the original Excel files with all of the monthly data described above for residential and SGS customers as a supplemental response to UDR 1.001.[3] Thus, the parties have had access to this data for many months.

Q. Did TEP submit any updates to these files since Direct Testimony?

A. Yes. TEP submitted a revised version of the residential data on June 6, 2016.[4] While we were preparing to update the models for Rebuttal, we found a formula error that resulted in the processing of only the first 11,000 or so observations. This formula error had only a slight effect. No updates were submitted for the SGS analysis.

Q. How were the monthly data described above used for developing three-part rates and analyzing bill impacts for residential customers?

A. The Company set up an analysis using 45 monthly kWh groupings beginning with 100 kWh per month up to 4,500 kWh per month in 100 kWh increments. We then calculated monthly bills for each of the 45 monthly usage levels under both current and proposed two-part rates.

Q. How did the Company determine the appropriate levels for demand and energy charges in the proposed residential three-part rates?

A. To develop the proposed three-part rates, TEP used its proposed residential two-part rates as the benchmark. Usually, when designing rates and calculating the levels of individual charges, rate analysts will perform a revenue proof. In this process, the rate analyst has a revenue target for the particular rate and is able to adjust the charges using the test-year

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[3] See Excel files "TEP 2015 RES Load-PV Data.xlsx" and "TEP 2015 SGS Load-PV Data.xlsx", which were submitted with TEP's Supplemental Response to UDR 1.001 dated December 1, 2015.

[4] See Excel file "TEP 2015 RES Load-PV Data_rev 06-03-16.xlsx", which was submitted by TEP as a supplement to UDR 1.001 dated June 6, 2016.

billing determinants until the desired revenue target is reached. In this case, because this is a new rate and kW billing data are incomplete, the first cut at a revenue proof must be estimated.

One other factor that TEP considered was that the resulting demand charges needed to have some basis in the Company's costs. In order to make sure the demand charges are cost-based, the Company referred to its Class Cost of Service Study ("CCOSS"). That study identifies demand related costs in the residential class of $20.61 for production, $5.67 for transmission, and $6.24 for distribution for a total of $32.52.[5] Given these results, we determined that there would be no difficulty developing residential demand rates that would be defensible as cost based.

Q. Please describe the process TEP used to arrive at the demand and energy charges in the proposed residential three-part rates.

A. First, the Company assigned load factors to each of the 45 monthly usage levels using the estimated regression parameters described earlier. This yielded a monthly billing kW for each of the 45 monthly kWh levels. Once monthly billing kW are assigned, monthly bills with a demand charge can be calculated.

Second, TEP calculated the number of sample observations in each of the 45 monthly kWh usage groupings from the 14,186 sample observations discussed previously. Using this distribution, TEP calculated total non-fuel revenues collected from the Company's proposed two-part rate. This becomes something like a revenue target for the three-part rates.

[5] 2015 TEP Schedule G - COSS Competitively Sensitive Confidential.xlsx submitted with TEP's Rate Filing.

Finally, the relative magnitudes of demand and energy charges must be determined. The Base Power and PPFAC charges can be ignored in this analysis because they will be the same in both cases. One consideration in designing this three-part rate is that customers with higher load factors will see lower monthly bills than customers with the same usage and lower load factors. This presents two issues. First, because this is an optional rate there will be a self-selection bias leading to a revenue shortfall. In other words, customers with higher load factors will choose the three-part rate and see lower bills with no changes in behavior. This is exacerbated by the inclining block structure of the two-part rate, which allocates a disproportionate amount of costs to higher users. Second, as customers increase their monthly load factor, above some level they will begin to see lower bills when compared to a two part rate.

Q. How did TEP resolve the issues identified in the previous response?

A. To mitigate the self-selection issue, TEP decided to propose a tiered demand rate with a cutoff at 7 kW. Given the estimated load factor distribution, this resulted in the second tier becoming effective at about 1,500 kWh per month of consumption. This by no means eliminates the self-selection problem, but mitigates it slightly.

With respect to the load factor level at which customers begin to see benefits, TEP first identified the mean and median load factors in the sample data. The mean and median monthly load factors for the customers in the sample were approximately 22% and 21%, respectively. The Company decided to set the demand charges at levels that would encourage customers to improve their load factors above the sample average, and the charges the Company proposed in its Application begin to result in lower monthly bills at load factors just above 24%.

Q. Please describe how TEP evaluated the impacts of the proposed three-part rates and changes to NEM on new residential DG customers.

A. In the same model used to develop three-part rates, TEP used the monthly values estimated in the previously discussed data development process for PV output, net TEP deliveries to PV customers, and net exports to TEP from PV customers to estimate bill impacts on new residential DG customers. This process was relatively straightforward, but some modeling enhancements have been made since the Company's Direct Testimony. These will be described later in my testimony.

Q. How did TEP develop the proposed three-part rates and evaluate changes to NEM for SGS customers?

A. TEP used the same process for the SGS class that it used for residential. One minor difference is that monthly bill comparisons are presented for 53 levels of monthly usage ranging from 150 kWh per month to 20,000 kWh per month.

Q. Did TEP make these residential and SGS analyses available to all parties?

A. Yes. TEP submitted the original Excel files with all of the analyses described above for residential and SGS customers as a supplemental response to UDR 1.001.[6]

Q. Did TEP submit any updates to these files since Direct Testimony?

A. Yes. TEP submitted a revised version of the residential three-part rate and DG analyses on June 6, 2016.[7] Because of the aforementioned formula error in the data underlying the residential analyses, some results changed slightly. No updates were submitted for the SGS analysis.

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[6] See Excel files "2015 TEP R-01 Demand-PRS.xlsx" and "2015 TEP GS-10 Demand-PRS.xlsx", which were submitted with TEP's Supplemental Response to UDR 1.001 dated December 1, 2015.

[7] See Excel file "2015 TEP R-01 Demand-PRS_rev 06-03-16.xlsx", which was submitted by TEP as a supplement to UDR 1.001 dated June 6, 2016.

Q. Did the update to the residential three-part and DG analyses have any impact on TEP's original proposals?

A. No, it did not.

Q. Did TEP submit any bill comparisons for residential and SGS customers taking service under the Company's proposed three-part rates or changes to NEM?

A. Yes. TEP submitted the required monthly bill impacts in its filed Schedule H-4 (Exhibit CAJ-3 to the Direct Testimony of TEP witness Mr. Jones) for the proposed residential and SGS three-part rates as well as their time-of-use variants. In the Company's Schedule H-4, bill impacts are provided for full requirements customers at a minimum of six different monthly usage levels.

In addition, in the models TEP used to develop the proposed three-part rates and submitted in Excel files in discovery, bill comparisons for full requirements customers were presented for 45 different usage levels for residential customers and 53 usage levels for SGS. These files also show extensive bill comparisons for new DG customers using the data described earlier in my testimony.

Finally, TEP provided residential bill comparisons for its proposals in the Direct Testimony of Company witness Dallas Dukes. In Mr. Dukes' Direct Testimony, three summary tables with results from TEP's analyses are presented[8] for (1) new residential DG customers on the Company's proposed two-part rate with proposed changes to NEM, (2) full requirements customers on the Company's proposed three-part rate, and (3) new residential DG customers on the Company's proposed three-part rate. In these tables, monthly bill comparisons are presented at usage levels of 500 kWh, 900 kWh, 1,200

[8] Direct Testimony of Dallas Dukes, 21:3-19, 25:1-6, 29:1-16.

kWh, and 1,500 kWh. These tables are reproduced as **Exhibit RDB-R-1** to my testimony for reference.

Q. You mentioned earlier in your testimony that TEP had made some modeling enhancements for the purposes discussed. Why did the Company feel it necessary to make changes?

A. As with any endeavor, one learns from experience. It is not news to anyone that TEP's sister electric utility, UNS Electric, is also in the midst of a rate proceeding with many of the same issues. While the two proceedings are separate, the Companies' rate design staffs are one and the same. The current UNS Electric proceeding is in a more advanced phase than this case and advances have been made by the parties in terms of analyzing these issues. The Company feels at this point that this proceeding can benefit from the advances made in the UNS Electric case.

Q. Please describe the modeling enhancements TEP has made for the purpose of analyzing its residential and SGS proposals?

A. One major enhancement has been the addition of an improved revenue proof model[9] similar to that used in the UNS Electric case. As I mentioned earlier, a revenue proof is a necessary tool in designing rates and charges. For example, the residential three-part rate design revenue model uses a sample of 16,963 TEP residential customers (a slightly modified version of a total sample of 17,270) and calculates monthly bills for the test year under both the Company's proposed two-part and three-part rates. This allows TEP to design the three-part rate to collect the same revenue for the sample as that collected by its proposed two-part rate, which has undergone a full revenue proof.

[9] See TEP Rebuttal workpapers "2015 TEP RES Dem Rate Rev_rb-FINAL.xlsx" and "2015 TEP SGS Dem Rate Rev_rb-FINAL.xlsx".

The other changes relate to the bill comparison analyses for full-requirements and new DG customers. First, TEP improved the NEM monthly banking and rollover calculations with three changes. The first improvement involved changing the NEM monthly banking and rollover period from a calendar year to the October to September cycle consistent with TEP's Net Metering tariff. Second, TEP added more sophistication to the monthly banking and rollover calculations to make them more accurate. Finally, TEP rearranged the order of months in the analyses to be consistent with the July 2014 to June 2015 test year. This change impacts the NEM monthly banking and rollover calculations because it places a customer's month-to-month usage in the correct chronological order.

Lastly, two corrections were made to the model. An option was removed for scaling the PV hourly profile that allowed the NREL SAM hourly profile to be scaled by monthly rather than annual customer usage. This option was an artifact from an early version of the model that had not been removed from the version used to develop the rates proposed in TEP's Application. Second, the seasonal definitions were changed to correctly assign the summer months as May through September.

Q. Do you have any further comments regarding the Company's three-part rate analyses for its Rebuttal case?

A. Yes, I have one final comment regarding the load profiles used for the residential and SGS three-part rate analyses in the Company's Rebuttal case. As I explained earlier, the Company based its proposed residential three-part rate design and all subsequent analyses on a sample of 14,186 TEP residential customer hourly load profiles. However, the Company provided raw hourly load profile data to the parties in this case in the response to RUCO DR 7.11. This response consisted of a sample of 17,270 TEP residential load profiles drawn for the period from July 2013 through 2015, of which the previous sample of 14,186 is largely a subset. Using the sample of 17,270 from the response to RUCO DR

7.11, TEP removed 307 observations with less than 3 months of usage data or less than 5 kWh consumption per month for a remaining sample of 16,963 observations. Because all parties have access to this data set, TEP is using this sample of 16,963 observations for all residential three-part rate analyses in the Rebuttal phase of this proceeding. Also, since both data sets represent large statistically significant samples with large amounts of overlap, the results from using either set will be essentially identical.

The Company is basing its SGS three-part rate analyses on an updated version of the hourly profiles used proposed rates in TEP's Application. As I explained earlier, the SGS analysis for the Company's Direct Testimony was based on a random sample of 5,550 hourly load profiles. The Company is providing that hourly sample, which consists of 6,251 SGS customer hourly load profiles, to the parties in response to Vote Solar DR 8.1. After removing 560 observations with less than 3 months of data or average monthly usage less than 5 kWh, the resulting sample consists of 5,691 observations. This SGS sample is used for the results in Section III of my testimony.

Q. What impacts do these modeling enhancements and the additional data set have on TEP's residential bill comparison analyses?

A. I have presented another version of the residential bill comparison tables from TEP witness Dallas Dukes' Direct Testimony as **Exhibit RDB-R-2**. This version of the tables uses the rates proposed in the Company's Application, the most recent version of TEP's residential models described above, and the modified load profile data set of 16,963 observations submitted by the Company in response to RUCO DR 7.11.[10] The impacts of the modeling and data changes are again relatively minor.

[10] See TEP Rebuttal workpaper "2015 TEP R-01 Demand-PRS_rdb-r2.xlsx".

Q. What are your conclusions in light of these results?

A. TEP's original approach to designing the proposed three-part rates and analyzing the impacts on new DG customers is quite robust. Even after significant changes and enhancements to the Company's approach, the results changed little. For the example mentioned earlier, a new DG customer using an average of 900 kWh per month on the Company's proposed three-part rate and receiving the proposed Renewable Credit Rate for hourly PV exports would save $57.85 per month from full-requirements service, which is an additional $1.98 over TEP's original estimate. The monthly savings for a new DG customer using 1,200 kWh per month under the same scenario decreased by $0.61 per month over the Company's originally filed estimate.

III. TEP'S REBUTTAL PROPOSALS FOR RESIDENTIAL AND SGS THREE-PART RATES.

Q. Has TEP changed any of its proposals for residential and SGS three-part rates for Rebuttal?

A. Yes. TEP witness Mr. Jones is sponsoring the Company's Rebuttal proposals for residential and SGS three-part rates. The only changes the Company is proposing in Rebuttal are revised rates and charges based on the revised TEP revenue requirement. I address TEP's proposed changes in this section of my testimony.

Q. Please describe the Company's Rebuttal proposal for residential three-part rates.

A. In Rebuttal, the Company is proposing three-part RES-D and RES TOU-D rates with the following elements:

- A monthly Basic Service Charge of $17.00.
- Demand charges of $7.40/kW for the first 7 kW of billing demand and $11.90/kW for all billing demand greater than 7 kW with billing demand defined as the maximum one-hour average kW during the billing month.

- An Energy Delivery Charge of $0.02492/kWh for all billing kWh.
- All other charges equal to those in the Company's equivalent two-part tariff for RES and RES-TOU service.

Q. Has TEP performed any bill comparison analyses for the three-part residential rates the Company is proposing in Rebuttal?

A. Yes, in addition to the residential bill comparisons for full requirements customers submitted by TEP in Schedule H-4 and at the 45 usage levels from 100 kWh to 4,500 kWh per month in the Company's three-part rate comparison model,[11] TEP is also submitting a residential revenue model[12] that has monthly bill calculations and comparisons for every one of the 16,963 observations in the residential load profile sample. In addition, the tables below are reproduced in the same form as those in the Direct Testimony of Company witness Dallas Dukes and summarize bill impacts for residential customers using 500, 900, 1,200, and 1,500 kWh per month. All DG scenarios assume a PV system sized to offset 100% of customer usage annually.

The first table compares monthly customer bills calculated under the Company's proposed two-part RES rate for full requirements, current NEM, and bill credits to new DG customers for hourly exports at the proposed Renewable Credit Rate.

[11] See "2015 TEP RES Demand-PRS-NCP_rb-FINAL.xlsx" submitted with Company's Rebuttal workpapers.
[12] See "2015 TEP RES Dem Rate Rev_rb-FINAL.xlsx" submitted with Company's Rebuttal workpapers.

Monthly Usage	RES: Full Requirements Service	RES: DG, Current NEM	RES: DG, Bill Credit for Hourly Exports
500 kWh per Month			
Monthly Non-Fuel Cost Recovery	$48.89	$17.00	$35.22
Average Monthly Bill (pre-tax)	$72.89	$20.81	$33.45
Unrecovered Non-Fuel Costs	NA	$31.89	$13.67
Monthly Bill Savings	NA	$52.08	$39.43
900 kWh per Month			
Monthly Non-Fuel Cost Recovery	$80.81	$17.00	$53.90
Average Monthly Bill (pre-tax)	$120.19	$20.40	$46.40
Unrecovered Non-Fuel Costs	NA	$63.81	$26.91
Monthly Bill Savings	NA	$99.79	$73.79
1,200 kWh per Month			
Monthly Non-Fuel Cost Recovery	$105.76	$17.01	$63.36
Average Monthly Bill (pre-tax)	$156.70	$19.84	$53.41
Unrecovered Non-Fuel Costs	NA	$88.75	$42.39
Monthly Bill Savings	NA	$136.86	$103.28
1,500 kWh per Month			
Monthly Non-Fuel Cost Recovery	$130.69	$17.01	$76.29
Average Monthly Bill (pre-tax)	$193.12	$19.57	$63.11
Unrecovered Non-Fuel Costs	NA	$113.68	$54.40
Monthly Bill Savings	NA	$173.55	$130.01

The table below compares monthly customer bills calculated under the Company's proposed residential two-part RES and three-part RES-D rates for full requirements customers.

Average Monthly Usage	Average Monthly Load Factor	Average Monthly Bill (pre-tax)		
		RES	RES-D	Difference
500 kWh	18.9%	$72.89	$79.92	$7.03
900 kWh	23.2%	$120.19	$117.47	($2.72)
1,200 kWh	25.2%	$156.70	$145.74	($10.96)
1,500 kWh	26.8%	$193.12	$175.66	($17.46)

The table below compares monthly customer bills calculated under the Company's proposed two-part RES rate for full requirements and new DG customers compensated

for hourly exports at the Renewable Credit Rate, along with new DG customers on the proposed three-part RES-D with the same credits for hourly exports.

Monthly Usage	RES: Full Requirements Service	RES: DG, Bill Credit for Hourly Exports	RES-D: DG, Bill Credit for Hourly Exports
500 kWh per Month			
Monthly Non-Fuel Cost Recovery	$48.89	$35.22	$50.71
Average Monthly Bill (pre-tax)	$72.89	$33.45	$49.20
Unrecovered Non-Fuel Costs	NA	$13.67	-$1.82
Monthly Bill Savings	NA	$39.43	$23.69
900 kWh per Month			
Monthly Non-Fuel Cost Recovery	$80.81	$53.90	$68.99
Average Monthly Bill (pre-tax)	$120.19	$46.40	$61.74
Unrecovered Non-Fuel Costs	NA	$26.91	$11.81
Monthly Bill Savings	NA	$73.79	$58.45
1,200 kWh per Month			
Monthly Non-Fuel Cost Recovery	$105.76	$63.36	$79.58
Average Monthly Bill (pre-tax)	$156.70	$53.41	$69.90
Unrecovered Non-Fuel Costs	NA	$42.39	$26.18
Monthly Bill Savings	NA	$103.28	$86.80
1,500 kWh per Month			
Monthly Non-Fuel Cost Recovery	$130.69	$76.29	$92.98
Average Monthly Bill (pre-tax)	$193.12	$63.11	$80.08
Unrecovered Non-Fuel Costs	NA	$54.40	$37.71
Monthly Bill Savings	NA	$130.01	$113.05

Q. Please describe the Company's Rebuttal proposal for SGS three-part rates.

A. In Rebuttal, the Company is proposing three-part basic SGS and SGS TOU rates with the following elements:

- A monthly Basic Service Charge of $27.00.
- Demand charges of $9.60/kW for the first 7 kW of billing demand and $13.75/kW for all billing demand greater than 7 kW with billing demand defined as the maximum one-hour average kW during the billing month.
- Energy Delivery Charges of $0.05777/kWh for all summer billing kWh and $0.04777/kWh for all winter billing kWh.

- All other charges equal to those in the Company's equivalent two-part tariff for SGS and SGS-TOU service.

Q. Has TEP performed any bill comparison analyses for the three-part SGS rates the Company is proposing in Rebuttal?

A. Yes, in addition to the SGS bill comparisons for full requirements customers submitted by TEP in Schedule H-4 and at the 53 usage levels from 150 kWh to 20,000 kWh per month in the Company's three-part rate comparison model,[13] TEP is also submitting a SGS revenue model[14] that has monthly bill calculations and comparisons for every one of the 5,691 observations in the SGS load profile sample. In addition, I am presenting bill comparisons below for SGS customers using 300, 1,200, 2,400, and 5,000 kWh per month. All DG scenarios assume a PV system sized to offset 100% of customer usage annually.

The first table compares monthly customer bills calculated under the Company's proposed two-part SGS rate for full requirements, current NEM, and with bill credits to new DG customers for hourly exports at the proposed Renewable Credit Rate

[13] See "2015 TEP SGS Demand-PRS-NCP_rb-FINAL.xlsx" submitted with Company's Rebuttal workpapers.

[14] See "2015 TEP RES Dem Rate Rev_rb-FINAL.xlsx" submitted with Company's Rebuttal workpapers.

Monthly Usage	SGS: Full Requirements Service	SGS: DG, Current NEM	SGS: DG, Bill Credit for Hourly Exports
300 kWh per Month			
Monthly Non-Fuel Cost Recovery	$49.96	$27.55	$42.68
Average Monthly Bill (pre-tax)	$70.72	$48.96	$64.09
Unrecovered Non-Fuel Costs	NA	$22.41	$7.28
Monthly Bill Savings	NA	$21.76	$6.63
1,200 kWh per Month			
Monthly Non-Fuel Cost Recovery	$133.39	$28.73	$87.39
Average Monthly Bill (pre-tax)	$215.77	$50.50	$109.68
Unrecovered Non-Fuel Costs	NA	$104.66	$46.00
Monthly Bill Savings	NA	$165.27	$106.09
2,400 kWh per Month			
Monthly Non-Fuel Cost Recovery	$249.77	$31.41	$149.66
Average Monthly Bill (pre-tax)	$414.22	$55.03	$173.21
Unrecovered Non-Fuel Costs	NA	$218.36	$100.11
Monthly Bill Savings	NA	$359.19	$241.02
5,000 kWh per Month			
Monthly Non-Fuel Cost Recovery	$502.30	$36.33	$293.36
Average Monthly Bill (pre-tax)	$844.72	$62.52	$319.61
Unrecovered Non-Fuel Costs	NA	$465.97	$208.94
Monthly Bill Savings	NA	$782.20	$525.11

The table below compares monthly customer bills calculated under the Company's proposed residential two-part SGS and three-part SGS-D rates for full requirements customers.

Average Monthly Usage	Average Monthly Load Factor	Average Monthly Bill (pre-tax)		
		SGS	SGS-D	Difference
300 kWh	24.2%	$70.72	$79.57	$8.85
1,200 kWh	32.7%	$215.77	$218.92	$3.15
2,400 kWh	41.3%	$414.22	$394.43	($19.79)
5,000 kWh	49.0%	$844.72	$787.56	($57.16)

The table below compares monthly customer bills calculated under the Company's proposed two-part SGS rate for full requirements and new DG customers compensated

for hourly exports at the Renewable Credit Rate, along with new DG customers on the proposed three-part SGS-D with the same credits for hourly exports.

Monthly Usage	SGS: Full Requirements Service	SGS: DG, Bill Credit for Hourly Exports	SGS-D: DG, Bill Credit for Hourly Exports
300 kWh per Month			
Monthly Non-Fuel Cost Recovery	$49.96	$42.68	$54.02
Average Monthly Bill (pre-tax)	$70.72	$64.09	$75.56
Unrecovered Non-Fuel Costs	NA	$7.28	-$4.07
Monthly Bill Savings	NA	$6.63	-$4.84
1,200 kWh per Month			
Monthly Non-Fuel Cost Recovery	$133.39	$87.39	$110.71
Average Monthly Bill (pre-tax)	$215.77	$109.68	$133.26
Unrecovered Non-Fuel Costs	NA	$46.00	$22.69
Monthly Bill Savings	NA	$106.09	$82.51
2,400 kWh per Month			
Monthly Non-Fuel Cost Recovery	$249.77	$149.66	$168.20
Average Monthly Bill (pre-tax)	$414.22	$173.21	$191.95
Unrecovered Non-Fuel Costs	NA	$100.11	$81.57
Monthly Bill Savings	NA	$241.02	$222.27
5,000 kWh per Month			
Monthly Non-Fuel Cost Recovery	$502.30	$293.36	$321.79
Average Monthly Bill (pre-tax)	$844.72	$319.61	$348.36
Unrecovered Non-Fuel Costs	NA	$208.94	$180.51
Monthly Bill Savings	NA	$525.11	$496.36

IV. RESPONSE TO STAFF'S TESTIMONY.

Q. Have you reviewed the rate design testimony submitted by Staff?

A. Yes, I have.

Q. What comments do you wish to make?

A. My comments on Staff testimony have only to do with providing additional information requested by Staff witness Howard Solganick.

Q. What additional information has Mr. Solganick requested from the Company?

A. On page 32 of his testimony, Staff witness Mr. Solganick states the following:

> The Company has not defined the source of the various values and tiers within the proposed demand rates. Also, the demand charge will apply to all time periods. The Company has not explained the theory and background of these rates, and the Company should provide more support in its Rebuttal testimony.[15]

Q. Where can Mr. Solganick, and all other parties to this proceeding, find the information requested by Mr. Solganick?

A. Sections II and III of my Rebuttal testimony provide the information requested by Mr. Solganick. I believe that the explanations and background given there along with the documents cited, all of which have been submitted by the Company, are responsive to Mr. Solganick's request.

With respect to the theory underlying the applicability of the Company's proposed residential and SGS demand rates, TEP witness Dr. Overcast addresses the issues in his Rebuttal Testimony.

V. <u>RESPONSE TO SOLON'S TESTIMONY.</u>

Q. Have you reviewed the rate design testimony submitted by SOLON?

A. Yes, I have.

[15] Direct Testimony of Howard Solganick ("Solganick"), 32:8-11.

Q. Please provide your general thoughts on SOLON's testimony.

A. SOLON's rate design testimony submitted by Mr. Brian A. Seibel is replete with unfounded criticism and hyperbole. For example, throughout Mr. Seibel's testimony he uses the phrase "wide ranging, aggressive, and unprecedented"[16] to describe nearly all of the Company's rate design proposals including a proposed demand ratchet for a new MGS rate class. Far from unprecedented, demand ratchets are present in TEP's current LGS and LLP tariffs and have been a prevalent element of utility industry rate design for years. Because of the exaggerated nature of SOLON's attacks on the Company in its testimony, it is difficult to distinguish Mr. Seibel's criticisms from his posturing.

Q. What areas of SOLON's rate design testimony do you address in your testimony?

A. SOLON witness Mr. Seibel extensively criticizes the Company's modeling efforts and approach to analyzing the customer impacts of its proposed three-part rates for residential and SGS rate classes and changes to the Company's Net Metering rider. I address Mr. Seibel's comments and criticisms related to these issues in my testimony.

Q. One common theme in Mr. Seibel's testimony is that the Company did not use any actual TEP customer data in its analysis of the proposed three-part rates and changes to NEM. How do you respond?

A. As I mentioned earlier, the Company used statistically valid random samples of hourly load data for 14,186 actual TEP residential customers and 5,550 actual TEP SGS customers to develop monthly data for its analyses. Because these data were converted from hourly to monthly and analyzed as monthly summaries does not negate the fact that they were obtained from actual TEP customer hourly load profiles.

[16] Direct Testimony of Brian A. Seibel ("Seibel"), 27:6, 41:8, 51:8-9, 60:8-9, 70:2-3, and 78:3-4.

Q. On page 9 of his testimony, Mr. Seibel states that he expects a "responsible, fulsome analysis would include substantial customer data from the test year, unaltered in any way" and recommends that "at least 30% of each rate class be represented, with the selected customers evenly dispersed between the minimum and maximum load factor for each rate class."[17] Please discuss Mr. Seibel's recommendation.

A. Mr. Seibel's recommendation is impractical and inconsistent with statistical sampling theory. It would require a sample of over 112,000 TEP residential customers for performing a bill impact analysis. Mr. Seibel has attempted to clarify his recommendation in a response to a TEP data request, TEP DR 2.02, which I am providing as **Exhibit RDB-R-3**.[18] In the response to TEP DR 2.02, Mr. Seibel recommends first separating data into customer classes, "specifically Residential, Commercial, and Industrial." Second, Mr. Seibel recommends that the class-level data be separated into percentile strata by load factor. Finally, he recommends that each percentile stratum be sampled by randomly drawing 30% of the observations from each percentile. So, in essence, Mr. Seibel is recommending a stratified random sample consisting of 30% of the observations within each percentile stratum and, as a result, within each customer class.

Q. How does Mr. Seibel arrive at a sample size of 30% of the population?

A. In his response to TEP DR 2.02, Mr. Seibel cites a website as the source (http://surveysystem.com/sscalc.htm) for his sample size calculation. He states that "Using a 99% confidence level and a 1% confidence interval, for each 35,000 sample set, you arrive at a sample size of 11,279, or 32%."[19] I accessed the website cited by Mr. Seibel and entered the same parameters that he used, a 99% confidence level and a 1% confidence interval, and a 35,000 population size, which confirmed Mr. Seibel's result. However, using the same 99% confidence level and 1% confidence interval, but using a

[17] Seibel Direct, 9:10-14.
[18] SOLON Response to TEP DR 2.02.
[19] SOLON Response to TEP DR 2.02.

population size of 375,000, which is the approximate number of TEP residential customers, I obtained a sample size of 15,934 or 4.2% of the population. This result is actually smaller than the residential sample of over 17,000 residential customers that TEP provided in response to RUCO DR 7.11 and is using for its residential analyses in Rebuttal. I am submitting a screen shot of this result as **Exhibit RDB-R-4**. Obviously, from these two results one must conclude that the relationship between the population size and the recommended sample size is not linear, but Mr. Seibel extrapolates as though it were. Upon further investigation, the sample size formulas used on the website Mr. Seibel cites are as follows:[20]

Sample Size

$$SS = \frac{Z^2 * (p) * (1-p)}{C^2}$$

Where:

Z = Z value (e.g., 1.96 for 95% confidence level)

p = percentage picking a choice, expressed as decimal (0.5 used for sample size needed)

c = confidence interval, expressed as decimal

Correction for Finite Population

$$\text{new } SS = \underline{SS / (1 + (SS\text{-}1/pop))}$$

Where: pop = population size

Q. What can you conclude from these formulas and other source information?

A. Three things. First, when the population size is known and finite, the relationship between the recommended sample size and the population size is definitely not linear. As the second equation shows, because of where population appears in the denominator of

[20] See http://www.surveysystem.com/sample-size-formula.htm .

the 'new SS' calculation, as population size increases, recommended sample size increases at a slower rate. In other words, doubling the population size does not require doubling the sample size. Extrapolating the 30% obtained by Mr. Seibel using a population of 35,000 would lead one to believe that a sample size of 112,500 TEP residential customers is required for a population of 375,000. However, we have seen that even using Mr. Seibel's recommended methodology only a sample size of 15,934 is necessary. Mr. Seibel's recommendation would oversample by approximately seven times that which is necessary at much greater time and expense, and would be no more statistically sound.

Second, when the population size is unknown, it is irrelevant. At the same website used by Mr. Seibel, expanded explanations are provided for the variables in the sample size formulas. In particular, the following comments on the relationship between sample size and population are instructive:

> Often you may not know the exact population size. This is not a problem. The mathematics of probability proves the size of the population is irrelevant unless the size of the sample exceeds a few percent of the total population you are examining. This means that a sample of 500 people is equally useful in examining the opinions of a state of 15,000,000 as it would a city of 100,000. For this reason, The Survey System ignores population size when it is "large" or unknown. Population size is only likely to be a factor when you work with a relatively small and known group of people.[21]

These comments further invalidate Mr. Seibel's extrapolation using the results for a population of 35,000. As I showed above, the formula gives a result for a population of

[21] See http://www.surveysystem.com/sscalc.htm .

375,000 that is only slightly larger than the result for a population of 35,000, not ten times larger as Mr. Seibel's extrapolation would yield.

Finally, Mr. Seibel's confidence level of 99% and confidence interval of 1% are well beyond those needed for this analysis. A 95% confidence level and 5% confidence interval, values much more in line with this type of analysis, would yield a minimum sample of 380 observations using a population of 35,000 and the calculator on the website cited by Mr. Seibel. For a population of 375,000, these parameters require a minimum sample size of 384 observations. The upshot of this is that the Company used residential and SGS customer samples larger than statistically necessary.

Q. On page 26 of his testimony Mr. Seibel states that "it is obvious the Company did not attempt to understand its own proposals on individual customers when it admits in SWEEP discovery request 2.15 that 'TEP has not conducted any analyses or reviewed previous studies to determine if a three-part rate is superior to a two-part time of use rate'" [sic][22]. Please discuss Mr. Seibel's criticism.

A. This statement by Mr. Seibel is a truncated version of the Company's actual response to SWEEP Data Request 2.15 and there is no period at the end of the quoted passage. It is unclear why Mr. Seibel chose to truncate the response in this context because he presented the Company's response to SWEEP DR 2.15 in its entirety on page 25 of his testimony and in his Exhibit E.[23] Where Mr. Seibel is mistaken in this statement is that the Company very well understands the impact of its own proposals on individual customers, it was just not the Company's primary goal to determine if a three-part rate is superior to a two-part time of use rate "in reducing peak demand,"[24] which are the four words that complete the sentence in the Company's actual response. Including these four

[22] Seibel Direct, 26:1-5.
[23] Seibel Direct, 25:4-11 and Exhibit E.
[24] Seibel Direct, 25:5-6.

words from the Company's response to SWEEP DR 2.15 changes the meaning significantly when quoted completely and accurately.

Q. On page 26 of his testimony Mr. Seibel states that "the Company has not used the actual data from a single real customer to understand the potential impacts."[25] Please respond.

A. As I mentioned earlier, the criticism that the Company did not use actual data from actual customers in its analyses is a common, repeated theme throughout Mr. Seibel's testimony. I will respond simply by repeating that the Company's analyses were performed using statistically valid random samples of hourly load profiles for 14,186 actual TEP residential customers and 5,550 actual TEP SGS customers.

Q. On page 29 of his testimony, Mr. Seibel takes issue with TEP using the terms "Net Metering" or "Net Hourly Metering" for its proposal to provide a bill credit for hourly PV exports at the Renewable Credit Rate instead of what he contends is the industry standard "Net Billing" for such an arrangement. Do you have any comment?

A. Only to say that it is a curious criticism to make by someone who gives the following definition of "Value of Solar" in his Exhibit A:

> Given the open dockets that share this title, I feel this is an important term to define. In my testimony, the "value of solar" is from the DG customer's perspective. To a DG customer, the value of a solar kWh is the average retail cost rate ($/kWh) their solar array offsets from their utility bill. So, for example, if a residential DG customer's rooftop solar array generated 1,000 kWh in a month and reduced their electric bill from $150 to $30, the "value of solar" would be:
>
> $$\textit{Value of Solar} = (150 - 30)/1000 = \$0.12/kWh$$ [26]

[25] Seibel Direct, 26:9-10.
[26] Seibel Direct, Exhibit B 1:4-13.

Q. Are you aware of Mr. Seibel's definition of "Value of Solar" being used in any utility industry venue?

A. No, I am not. For example, the December 3, 2013, Commission Decision No. 74202 in Docket No. E001345A-13-0248, which ordered the opening of the current Commission Docket No. E-00000J-14-0023, states that the purpose of the current docket is to "help inform future Commission Policy on ***the value that DG installations bring to the grid."*** [Emphasis added][27] In fact, it is this value that PV installations bring to the grid or to the utility system as a whole that have been the focus of all Value of Solar ("VOS") proceedings or tariffs of which I am aware. Another example, Austin Energy ("AE") in Austin, Texas, offers a Residential Solar tariff that compensates customers with an on-site solar PV system with a Value-of-Solar credit for each kWh produced.[28] In the study commissioned by the City of Austin to calculate the Value-of-Solar credit, the purpose of the study is stated as to "Quantify the comprehensive ***value of distributed PV to AE*** in 2006." [Emphasis added.][29]

Finally, a 2015 NREL report states that "a VOS rate is determined through a bottom-up calculation of each of the ***benefits and costs that distributed solar provides to or imposes on the electricity system***." [Emphasis added][30] It is obvious from all of the preceding examples that the standard utility industry definition for the concept of "Value of Solar" encompasses distributed PVs benefits and costs to the entire utility system and is much more general than Mr. Seibel's narrow definition.

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[27] Order No. 74202, Docket No. E001345A-13-0248, 30:9-10.

[28] City of Austin Electric Rate Schedules, Residential Solar tariff.

[29] "The Value of Distributed Photovoltaics to Austin Energy and the City of Austin," Clean Power Research, March 17, 2006, p. ES-1.

[30] "Value of Solar: Program Design and Implementation Considerations," NREL, March 2015, p. v.

Q. On page 29 of his testimony, Mr. Seibel states that "access to an instantaneous solar production profile and a historical instantaneous usage profile"[31] would be absolutely necessary to evaluate the economics of a solar project with the Company's net metering proposal. Do you agree with Mr. Seibel?

A. No, I do not. Hourly interval data is sufficient. The Company is proposing that the billing demand for its proposed residential and SGS three-part rates be the highest measured average demand over a 60-minute clock-hour. Also, the output from a customer's DG system will be credited by the Company at the proposed "Renewable Credit Rate" on the same average clock-hour basis so any credits paid by the Company to the customer will be consistent with hourly billing kWh. Even if data could be retrieved at smaller intervals it is of questionable value to the analysis because it would be irrelevant for billing purposes. Finally, the theoretical notion of "instantaneous" data is problematic. In real number analysis there are an infinite number of points between two discrete points, regardless of the distance between them. I have no idea how Mr. Seibel would recommend capturing or storing such data. If Mr. Seibel has a specific definition for "instantaneous" that embodies some discrete period (i.e., 1 second, 1 minute, etc.), he did not present it in his testimony.

Q. On page 30 of his testimony, Mr. Seibel states the following:

> **Despite having 19,110 AMR meters installed for commercial customers at the start of the Test Year that log usage in 60-minute or 15-minute intervals (SOLON DR 2.10), the Company has not provided any hourly data for commercial customers of any size, despite requests from SOLON and Staff (SOLON DR 3.2, Staff DR 20.08).[32]**

Please respond.

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[31] Seibel Direct, 29:11-12.
[32] Seibel Direct, 30:13-17.

A. In support of Mr. Seibel's assertion, he cites the Company's responses to SOLON DR 3.2 and Staff DR 20.08, which he provides as Exhibits G and H, respectively. The easy response to Mr. Seibel's assertion is that neither of these data requests ask for hourly data for any customers. The Company's responses to the data requests provided exactly what was being asked. Mr. Seibel's Exhibit H is a copy of the Company's response to Staff DR 20.08 while his Exhibit G only provides SOLON DR 3.2 without the Company's response. The Company provided the response to SOLON DR 3.2 on June 24, the day that Intervenor rate design testimony was filed so Mr. Seibel could not have provided it in his exhibit. I am providing a copy of the Company's responses to SOLON DR 3.1 and 3.2 as **Exhibit RDB-R-5**, which direct SOLON to the data requested.

Q. On page 30 of his testimony, Mr. Seibel says that he only used data for the 12 months from January 2014 through December 2014 because if he "used data strictly from the test year (June 2014 through May 2015), any customer usage patterns in at the end of May would not carry through."[33] Please comment.

A. The test year in this proceeding is from July 1, 2014 to June 30, 2015.

Q. On page 31 of his testimony, Mr. Seibel says that the Company used none of its "unaltered, actual customer load profiles in their analysis of net metering, a Renewable Credit Rate, or customer bill impact with new two-part and three-part rate plan proposals."[34] Do you agree?

A. No. TEP used random samples of 14,186 residential and 5,550 SGS hourly customer load profiles to analyze all of these items. The fact that the hourly profiles were first processed with SAS and then transferred to Excel for further analyses does not negate their use. All

[33] Seibel Direct, 30:25-26 to 31:1.
[34] Seibel Direct, 31:5-9.

monthly customer data and billing determinants used in the analyses were derived from unaltered, actual customer load profiles.

Q. On page 31 of his testimony, Mr. Seibel states that:

> **Second, the Company took the Sample Data and generated <u>average hourly load profiles</u> for five different customer percentiles. The hourly values appear to be averaged amongst a large group of residential customers. By averaging in this fashion, individual customer peaks unique to each customer are smoothed and not accurately represented. These unique customer peaks are paramount to a responsible analysis...When the Company averages numerous load profiles together, the provided hourly profiles result in abnormally high load factors.**[35]

Please comment.

A. Mr. Seibel's position is correct that averaging hourly load shapes among customers mutes the individual customer peaks, yields a flatter load curve, and results in abnormally high load factors. I would hope that any utility industry analyst who works with hourly load shapes understands the pitfalls of averaging hourly load shapes. The fact of the matter is that the Company only used the results of this averaging to approximate the monthly peak hours for the typical customer usage profile being analyzed so billing demands could be adjusted for PV output. However, these averaged load shapes were simply not used for the purpose asserted by Mr. Seibel.

Q. On page 32 of his testimony, Mr. Seibel states that:

> **Third, the Company took each hour from the <u>average hourly load profiles</u> and multiplied them by the following ratio:**

[35] Seibel Direct, 31:25-26 to 32:1-18.

Peak Demand (by Month) from Average Monthly Profile
Peak Demand (by Month) from Average Hourly Profile

The Company performed this calculation to shoehorn the average hourly load profile to fit the monthly load factors. These calculation steps result in five heavily modified load profiles to analyze the billing impacts to 350,000+ residential customers.[36]

Please discuss.

A. Mr. Seibel is correct that the Company made the calculations he specifies, but the Company did not "shoehorn" any average load profiles to fit monthly load factors. His characterization of how the Company used these calculations is incorrect. The average load profiles appear in the Excel models I discussed in Section II of my testimony, but they are not used to design any three-part rates or for full requirements bill analysis. They are only used to give some insight into how PV production might impact shifting and reduction of customer maximum demands.

To analyze the bill impacts of three-part rates, the only variables needed are monthly billing kWh and kW. Hourly load profiles are not a necessary element of customer bill comparisons and Mr. Seibel's overemphasis on them is a distraction. The fact that TEP converted actual hourly customer loads into monthly kWh and maximum kW summaries to calculate monthly bills does nothing to discredit the Company's analyses. The monthly load factors that resulted from the monthly billing kWh and maximum kW summaries and used in the analyses are the actual monthly load factors.

Finally, Mr. Seibel's criticism that the Company used "heavily modified load profiles" simply doesn't hold water. The load profiles on which Mr. Seibel spends an inordinate amount of his testimony, the average hourly load profiles, were only used by TEP to

[36] Seibel Direct, 32:20-26 and 33:1-3.

approximate the monthly peak hours for the typical customer usage profiles and to determine where billing demands should be adjusted for PV output. Furthermore, analysts in the utility industry use modified load profiles all the time. One of the major objectives of load research is to develop "typical" as opposed to "average" customer load profiles for analysis for the very reason that we are all aware of the pitfalls of using average load profiles. The fact of the matter is that, in this case, TEP used no modified load profiles in the manner alleged by Mr. Seibel.

Q. On page 33 of his testimony, concerning the NREL SAM hourly profiles used Mr. Seibel states that the Company "heavily and inaccurately scaled each hourly profile to align with [monthly] customer usage for each of the five previously described profiles."[37] What is your response?

A. Mr. Seibel is correct in describing this aspect of the original version of the analyses submitted by TEP. However, as I explain in Section II of my testimony this option from an early version of the model has been removed. The annual hourly PV shapes are currently scaled on an annual basis.

Q. Have you evaluated the impact of this change?

A. Yes, in Section II of my testimony I presented TEP's results after making this and other changes to TEP's models and concluded that the impacts of the changes were inconsequential. Nevertheless, TEP agrees with Mr. Seibel that annual usage is the correct method for scaling the hourly PV profiles. As I mentioned in Section II, TEP has largely adopted the model version used in the UNS Electric proceeding and the monthly scaling option had already been eliminated.

[37] Seibel Direct, 33:8-9.

Q. On pages 37-39 of his testimony, Mr. Seibel lists five issues that he maintains represent a series of "inaccuracies, discrepancies, or poor analysis"[38] in reference to the Company's originally submitted Excel models used to analyze three-part rate design and bill impact for TEP's residential and SGS customers. Please comment.

A. I will paraphrase Mr. Seibel's five issues and respond to each in order.

1. Issue: The hourly solar profiles are heavily modified to physically impossible values to more closely align with assumed monthly usage profiles.

   Response: This has been changed in the Company's most recent models. See the discussion in Section II of my testimony.

2. Issue: Instead of using the Company provided 17,296 usage profiles from actual customers, the Company uses questionable and misrepresentative methods to arrive at five average usage profiles as the sole basis for their analysis.

   Response: Far from being the "sole basis" for TEP's analysis, the average usage profiles cited by Mr. Seibel were not used for any purpose other than approximating the hour of the monthly maximum kW for the typical customer and to adjust billing kW for PV output. Mr. Seibel spends an inordinate amount of his testimony on this distraction. Again, TEP did not use this data in the way stated by Mr. Seibel; it was only used for the very limited purpose I have already explained. Also, the Company actually used a sample of 14,186 hourly profiles from TEP residential customers in the analyses. The 17,296 observation sample was provided by TEP in response to RUCO DR 7.11 and includes nearly all of the 14,186 observations used in TEP's analyses. As I discussed in Sections II and III of my testimony, TEP is using the larger customer sample for Rebuttal.

3. Issue: The Company does not use their own annual net metering reset policy at the end of September. Instead, the Company's analysis used December.

[38] Seibel Direct, 37:6-7.

Response: The original version of the Company's models used December as the reset. This has been changed to the end of September consistent with the Company's Net Metering Rider. See Section II of my testimony.

4. Issue: The Company's analysis of PV power exported to the grid and consumed by the customer is rooted from hard coded values that ignore accurate, calculated results from the Company's included hourly solar and usage profiles.

   Response: The "hard coded" monthly values for customer usage, customer peak demand, hourly DG customer net kWh from the utility, and hourly DG customer exports are all derived from the Company's hourly solar and usage profiles. They were processed in SAS prior to transfer to Excel and Mr. Seibel has misinterpreted where the "hard coded" monthly values originated.

5. Issue: The Company's analysis includes five customer load scenarios, all of which are average load scenarios, as mentioned in Issue 2. The Company did not run its model with any of its customers' load profiles when analyzing the impact when switching from a volumetric rate plan to a demand based plan.

   Response: See responses to Items 2 and 4.

Q. On pages 40-41 of his testimony, Mr. Seibel says that he was able to run each of the Company's 17,296 provided residential hourly load profiles through the Company's model and record data for all 17,296 load profiles. He also states that the process took 50 minutes. Does this sound reasonable?

A. I have no reason to doubt Mr. Seibel. However, I will say that evaluating the Company's proposal is the easy part and I commend Mr. Seibel for his input. Actually designing the proposed rates and making sure that they recover the proper revenue, are not unduly discriminatory, and balance the rate design goals of the Company and its customers is the difficult part. That process takes significantly more care and diligence than 50 minutes could possibly allow.

Q. What are the results and conclusions of Mr. Seibel's 50-minute exercise?

A. Mr. Seibel presents five high level findings on page 41 of his testimony and expands on them over the remaining 38 pages of his testimony. I will discuss the first three of Mr. Seibel's findings.

Q. Please discuss Mr. Seibel's first high level finding.

A. Mr. Seibel's first finding is that the Company's proposed three-part rate plans, as structured, ignore gradualism and result in extremely high levels of uncertainty for all residential customers with or without DG. Quite frankly, I'm at a loss to explain how such subjective conclusions can be gleaned from an objective analysis. Although Mr. Seibel presents many visual depictions of bill impacts under two-part and three-part rates, for both DG and non-DG customers, nowhere has he developed a way to measure "levels of uncertainty" so he can make any conclusion about whether levels of uncertainty will be high or low under the Company's proposals. Mr. Seibel's first high level finding just does not logically flow from the analysis he uses to support it and he gives little explanation of how he leapt from his analysis to his conclusion.

Q. In discussing his first finding on page 42 of his testimony, Mr. Seibel states that only "four highly modified profiles were used"[39] by TEP to present bill impacts for the residential and SGS customers with or without DG. Is this true?

A. No. First, the profiles used were not modified in the sense that Mr. Seibel describes in his testimony. They were simply monthly profiles derived from a sample of actual customer hourly profiles. Second, Mr. Seibel is referring only to the bill impacts presented in the Direct Testimony of TEP witness Dallas Dukes, which summarized bill impacts for residential customers at monthly usage levels of 500 kWh, 900 kWh, 1,200 kWh, and

[39] Seibel Direct, 42:16-17.

1,500 kWh. TEP, in the aforementioned Excel files submitted as workpapers in this proceeding, provided estimated monthly bill comparisons for many more customer load profiles. Finally, bill impacts are provided by applicants in a rate case for each rate class in the filed Schedule H-4 and that is exactly what TEP provided in this case. Because DG customers were not identified as a separate rate class means that only bill comparisons for full requirements customers are required in the Company's filed Schedule H-4 or any related filings. Here it seems that Mr. Seibel wants it both ways; DG customers are no different than other utility customers except when they are. Nonetheless, in this case TEP presented bill impacts for customers both with and without DG in several places.

Q. On page 44 of his testimony, Mr. Seibel presents a scatter diagram comparing residential customers taking full requirements service on the Company's proposed two-part and three-part rates and makes several conclusions.[40] Do you have any comments?

Yes. From this scatter diagram, Mr. Seibel concludes that "R-01 Demand bills are highly sporadic and unpredictable amongst all residential customers."[41] If I understand what Mr. Seibel is trying to say it's that because there is significant variation in monthly bills across the sample observations, therefore each residential customer faces sporadic and unpredictable outcomes under the Company's proposed three-part rate. However, Mr. Seibel is making a significant logical leap to equate variation across the sample of customers to unpredictability or uncertainty for a particular customer. Mr. Seibel is looking at cross-sectional variation across the sample observations and equating that to the variation or uncertainty that a single customer would face, but I would expect that a particular customer's individual load profile characteristics would show much less

[40] Seibel Direct, 45:14-26.
[41] Seibel Direct, 45:14-15.

variation than the sample as a whole. And that customer would be much more familiar with his or her usage characteristics than those of the sample as a whole.

Finally, TEP is proposing a three-part tariff as an optional rate for full requirements customers (i.e., customers that do not have rooftop solar or other generation). If a customer has high uncertainty about the rate offering's bill impact or does not have a load profile that would provide benefits, he or she surely has the option of staying on the two-part rate. However, I would be skeptical that the distribution of bill impacts across the sample of customers would have much influence on that particular individual's decision.

Q. Please discuss Mr. Seibel's second high level finding.

A. Mr. Seibel states that the Company must release commercial customer 15-minute interval data, and the Company has not adequately demonstrated rate plan impacts to commercial customers, with and without DG. First, I am at a loss to explain how Mr. Seibel arrived at this finding with respect to commercial customer interval data and commercial rate plan impacts based on the analysis of residential customer data described on page 40 of his testimony. Because Mr. Seibel suggests on page 41 of his testimony that he reached his high level findings as a result of this residential customer modeling exercise, his sudden pivot to a discussion of commercial customers is baffling. In fact, on page 51 of his testimony Mr. Seibel is suddenly discussing the Company's proposed MGS and LGS rate plans.

With respect to Mr. Seibel's demand that the Company release commercial customer 15-minute interval data, the Company provides, and will continue to provide, interval data in the form it is recorded. If a customer is on a tariff that defines billing demand as the highest measured average demand over a 60-minute interval, the meter for that customer may be set to record kW at hourly intervals or 15-minute intervals. If the customer's

billing demand is the highest demand measured over a 15-minute interval, the meter is set to record kW at 15-minute intervals. If customers move from a tariff with 60-minute interval demand to one with 15-minute interval demand, the meters will be reset to record at 15-minute intervals. Long story short, the Company cannot provide data it doesn't have.

Further, the Company will provide a customer's historical data to the customer upon request, if the data are available. However, the Company takes the confidentiality of its customers very seriously and protects it in accordance with Commission customer privacy rules.

Finally, in discussing his second finding, Mr. Seibel goes to some length to criticize the Company's maximum load and usage limits used to delineate the applicability of TEP's proposed commercial and industrial rate tariffs. Again, Mr. Seibel has identified limiting rate tariff applicability as another of the Company's "unprecedented", but at the same time widely used, utility practices.

Q. Please summarize Mr. Seibel's third high level finding.

A. Mr. Seibel states that an annual ratchet puts insurmountable pressure on commercial customers to strictly monitor demand, and ratchets disincentivize ***all*** DG, EE, and storage technologies.

Q. How does Mr. Seibel arrive at this finding?

A. In his analysis of this finding, Mr. Seibel compares one year of monthly bills for 11 schools billed on the Company's proposed MGS rate tariff both with and without the demand ratchet specified in the tariff. The proposed MGS ratchet specifies that a customer's billing demand be calculated as the greater of that month's actual measured

demand or 75% of the customer's highest billed demand over the previous 11 months, subject to a billing minimum of 20 kW. Mr. Seibel concludes that the schools would be "overbilled" by nearly $150,000 in the first year.[42]

The major flaw in Mr. Seibel's analysis is that he assumes the schools in his example will face the same rates and charges under both the ratchet and non-ratchet scenarios. When rates are designed, the charges embodied in them must be set at a level to recover all of the costs allocated to a rate class. Very simply, rates are calculated by dividing the costs allocated to a rate class by the test year billing units for that rate class. The costs allocated to a rate class will not change in the presence or absence of a billing demand ratchet. However, the charges calculated to recover the allocated costs will be higher once the ratchet is removed because the additional billing kW demand attributable to the ratchet will be removed. Even Mr. Seibel's own tables presented on page 62 of his testimony show measured demands lower than billing demands for many periods in his analysis. If measured demands without the proposed demand ratchet are used to design rates, the same allocated costs will be spread over fewer billing units and the resulting rates will necessarily be higher. Mr. Seibel seems to ignore this simple rate design concept in his analysis. Therefore, the alleged monetary impacts of his analysis presented on page 63 of his testimony are invalid. Furthermore, a customer cannot be billed accurately according to the terms and conditions of a rate tariff and be considered "overbilled".

Q. Please discuss Mr. Seibel's finding that demand ratchets disincentivize *all* DG, EE, and storage technologies.

A. The statement that demand ratchets disincentivize ***all*** DG, EE, and storage technologies is easily refuted. Obviously, many commercial and industrial customers with demand ratchets have undertaken DG and EE measures and it only takes one counter-example,

[42] Seibel Direct, 63:4.

although there are many more than one, to rebut Mr. Seibel's absolute. Mr. Seibel's statement also ignores the fact that there is an energy charge applicable to any additional energy consumed by a customer on a tariff with a demand ratchet, as if a positive energy charge is no incentive to consume less. Also, the current NEM framework that Mr. Seibel so champions is a true disincentive to storage technologies as long as DG customers are allowed to produce more energy than they use and exchange the excess for consumption in the future, thereby using the grid as a very inexpensive and reliable virtual battery while they avoid paying for much of the fixed cost of the grid.

VI. RESPONSE TO VOTE SOLAR'S TESTIMONY.

Q. Have you reviewed the rate design testimony submitted by Vote Solar?

A. Yes, I have.

Q. What comments do you have with respect to Vote Solar's rate design testimony?

A. I will address Vote Solar witness Ms. Briana Kobor's testimony insofar as it relates to TEP's proposed residential three-part rates, in particular, the Company's modeling and bill impact analyses and the cost basis for the proposed rates.

Q. On page 39 of her Direct Testimony Ms. Kobor criticizes TEP's presentation of residential three-part rate bill impacts because they are presented with only an average value for measured kW. Do you agree with Ms. Kobor's criticism?

A. No. First, bill comparisons for all customer classes are performed using some typical or average usage profiles. For TEP's customer classes with a demand charge, bill comparisons are presented in Schedule H-4 with only one assumed load factor and resulting billing kW for each monthly usage level. Ms. Kobor criticizes the Company's presentation, but makes no recommendations relating to the optimal number of usage

levels or load factors for presenting bill impacts. Ms. Kobor presents a scatter diagram of a sample of over 17,000 TEP full requirements residential customers that plots bill impacts on the proposed three-part rates relative to monthly usage level.[43] From this presentation one gets the idea that Ms. Kobor would recommend that customer bill impacts be presented for every customer in the sample.

Second, like SOLON witness Mr. Seibel, Ms. Kobor confuses the distribution of bill impacts across the customer class with those faced by an individual customer. On page 40 of her testimony, she states that "when the data is examined for the 2,150 customers in the sample that have an average monthly usage between 800 kWh and 1,000 kWh per month, the data reveals that these customers will have a large range of impacts."[44] The large range of impacts that concern Ms. Kobor are a consequence of the large range of impacts these customers have on the system. Also, TEP is proposing an ***optional*** three-part rate for full requirements residential customers. I can't imagine that the possible bill impacts of the optional three-part rate on other customers in the class is a relevant factor in an individual customer's decision about whether to choose the rate plan. Also, that particular customer's distribution of impacts is likely to be far smaller than the 2,150 customers in the sample cited by Ms. Kobor.

Q. On page 42 of her Direct Testimony Ms. Kobor states that "the data shows that 65% of customers are expected to face bill increases on a demand charge tariff" and "larger customers tend to be among the biggest savers on a demand charge rate."[45] Do you agree?

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[43] Direct Testimony of Briana Kobor ("Kobor"), Exhibit BK-2.
[44] Kobor Direct, 40:12-15.
[45] Kobor Direct, 42:9-11

A. No. First, TEP is proposing an ***optional*** three-part demand tariff for the customer class to which Ms. Kobor is referring. I would not ***expect*** 65% of customers to face bill increases under that scenario.

Second, Ms. Kobor fixates on the relationship between the bill impacts and customer monthly kWh usage. However, that correlation is spurious. The true correlation is between bill impacts and customer load factor. The fact that there is also an empirical relationship between customer size and load factor allows Ms. Kobor to muddy the waters by focusing only on customer monthly kWh usage. A higher usage customer with a low load factor will be more likely to see a bill increase and a lower usage customer with a high load factor will be more likely to see a bill decrease. This is illustrated in the simple example below showing bill comparisons for two full requirements residential customers, one using 400 kWh per month and another using 2,000 kWh per month. Average monthly bill impacts for both customers are shown using a 15% load factor and a 35% load factor. The bills are calculated before surcharges and taxes.

15% Load Factor		**Monthly Bills**		
Billing kWh	**Billing kW**	**2-part Rate**	**3-part Rate**	**Difference**
400	3.7	$ 57.75	$ 71.14	$ 13.39
2,000	18.3	$ 238.74	$ 326.39	$ 87.65
35% Load Factor		**Monthly Bills**		
Billing kWh	**Billing kW**	**2-part Rate**	**3-part Rate**	**Difference**
400	1.6	$ 57.75	$ 55.69	$ (2.05)
2,000	7.8	$ 238.74	$ 202.19	$ (36.55)

Q. What lessons can one gather from this example?

From the above table it is clear that the customer's load factor, not customer kWh usage, is the larger determinant of whether a customer will pay more or less on the proposed three-part rate. In the low load factor case, both the lower and higher usage customers pay higher bills on the three-part rate and both pay smaller bills on the three-part rate

with the 35% load factor. In other words a lower usage customer can lower their bill on a three-part rate by improving their load factor, but a low load factor customer cannot realize savings compared to a two-part rate just by getting bigger. The proposed three-part rate would provide the customer with the incentive to improve his or her load factor and customer load factor improvement benefits both the customer and the utility system.

Q. On page 42 of her testimony, Ms. Kobor has a discussion of whether TEP's proposed residential three-part rates are cost based. Do you have any comments on her discussion?

A. Yes. In her discussion, Ms. Kobor, citing the CCOSS submitted by TEP in its Application, asserts that "For the residential class this means that 19% of the residential costs that the cost of service study classifies as demand related are related to the residential class NCP, 39% of the costs are related to the CP, and 42% of the costs are unrelated to demand, but rather, are based on energy usage."[46] There is absolutely no way that 42% of residential costs from TEP's CCOSS could be based on energy usage without including fuel expense, which is not a candidate for a demand charge; rather fuel and purchased power costs are recovered through the Company's Base Power charge and PPFAC. To include fuel expenses in these percentages is misleading.

Q. Have you been able to replicate Ms. Kobor's percentages?

A. No, I have not. I have not been able to locate her calculations in her submitted workpapers and cannot replicate them from the total residential revenue requirement in the Company's CCOSS.[47] However, if one is looking only at Total Operations and Maintenance ("O&M") Expense for the residential class, the energy component is 42%. For the residential class, the demand component of the Company's Total O&M is $179.4

[46] Kobor Direct 44:11-14.

[47] 2015 TEP Schedule G - COSS Competitively Sensitive Confidential.xlsx submitted with TEP's Rate Filing.

million and the energy component is $129.6 million. While the energy component is 42% of energy and demand related Total O&M costs, Total O&M costs are only a part of the total residential revenue requirement. More important, the energy component of $129.6 million consists of Fuel Expense ($128.7 million) and Uncollectible Fuel Expense ($0.9 million), neither of which are candidates for recovery with a demand charge. Therefore, Ms. Kobor's assertion is a tacit admission that all of the Company's non-fuel and non-customer related costs are demand related and, therefore, recovery by a demand charge is cost based.

If one looks at the Company's entire residential class revenue requirement, the demand and energy components are $360.4 million and $129.6 million, respectively. The energy component makes up only 26% of energy and demand related costs. As I mentioned earlier, the two pieces of the $129.6 million energy component are fuel related and are not candidates for recovery by a demand charge in a three-part rate.

Q. On page 62 of her testimony, Ms. Kobor states that TEP "appears to have undergone no evaluation of the impact of its rate design proposals on small commercial customers."[48] Do you agree?

A. Absolutely not. Ms. Kobor uses TEP's response to EFCA DR 2.10 to conclude that the Company "appears to have undergone no evaluation" of the bill impacts the proposed three-part rates would have on TEP's SGS customers. In the data request in question, EFCA specifically asked for "equivalent tables to those on pg. 21 and pg. 29 [in Direct Testimony of TEP witness Dallas Dukes] referring to the bill impacts for residential NEM customers, for SGS, MGS, and LGS customers." EFCA was asking for bill comparisons in a very specific form that the Company did not have in its possession and the Company responded as such, but Ms. Kobor has attempted to represent the situation

[48] Kobor Direct, 62:16-17.

as one where the Company did not evaluate the proposals for small general service customers.

As I discussed extensively in Section II of my testimony, TEP used a random sample of 5,550 SGS customers to perform virtually the same analysis that it performed with residential customers. As I also explained earlier, the SGS three-part rate analysis submitted by the Company[49] contained monthly bill comparisons for full-requirements customers at 53 different monthly usage levels from 150 kWh per month to 20,000 kWh. Furthermore, all of the information contained in the tables requested in EFCA DR 2.10 is contained in the Company's SGS customer analysis. Nevertheless, I have developed tables for the SGS customer class similar to those requested in EFCA DR 2.10 with the rates proposed by TEP in Rebuttal and they are presented in Section III of my testimony.

Finally, the notion that TEP should be providing bill impact analyses for all types of DG customers, from the residential on up to the LPS rate class, is simply an attempt to keep throwing imaginary requirements at the process. If DG customers are no different than non-DG customers as Vote Solar and other Intervenors contend, they do not need to be evaluated separately. The extensive analyses TEP has provided on the impacts of the Company's proposals on both residential and SGS DG customers goes well beyond the necessary requirements.

VII. RESPONSE TO EFCA'S TESTIMONY.

Q. Have you reviewed the rate design testimony submitted by EFCA?

A. Yes, I have.

[49] See Excel file "2015 TEP GS-10 Demand-PRS.xlsx", which was submitted with TEP's Supplemental Response to UDR 1.001 dated December 1, 2015.

Q. Do you have any comments related to EFCA witness Mark Garrett's testimony?

A. Only a few. I was amused by Mr. Garrett's position that intra-class subsidies in rate classes with volumetric rates are a regulatory feature and not a bug. TEP witness Dr. Overcast will address that element of Mr. Garrett's testimony in more detail. My only other comments relate to Mr. Garrett's statements regarding residential and commercial load characteristics and TEP customer NEM rider eligibility.

Q. Please summarize Mr. Garrett's comments on residential and commercial load characteristics?

A. On page 23 of his Direct Testimony, Mr. Garrett states that "residential customers exhibit dramatically different and less consistent usage patterns than commercial and industrial customers. Demand charges can work as an approximation for non-residential causation of capacity costs because non-residential customers' maximum demands are usually coincident with system peak."[50] If Mr. Garrett is referring to usage patterns across customers in the respective rate classes, this statement should come as a surprise to anyone in the electric industry who has worked with actual load profiles. Commercial and industrial customers consist of schools, churches, restaurants, lodging, office buildings, manufacturing, warehouses, retail, strip malls, shopping malls, hospitals, grocery stores, convenience stores, and the list goes on. This heterogeneity of customer types makes it more challenging to develop a "typical" commercial customer load profile than a residential profile. To argue that residential customers exhibit dramatically different and less consistent usage patterns than the diverse commercial customer base is not empirically valid.

[50] Direct Testimony of Mark Garret ("Garrett"), 23:15-18.

Q. On page 8 of his testimony, Mr. Garrett's states that "NEM customers take service on the standard residential and small commercial rates."[51] Is the Company's Net Metering Rider restricted to customers who take service on the standard residential and small commercial rate tariffs?

A. No, it is not. Customers taking service on any of the Company's rate tariffs who have self-generation that meets the applicability requirements can also subscribe to TEP's Rider R-4, Net Metering for Certain Partial Requirements Service ("NEM Rider R-4"). TEP currently has NEM customers on Residential, Residential Lifeline, SGS, LGS, and LLP (proposed LPS) rate tariffs as well as the TOU variants of each. The Company is not proposing any changes to NEM Rider (proposed Rider 15) eligibility in this case.

Q. Do any of TEP's current NEM customers take service on a rate tariff with a demand charge?

A. Yes, TEP's LGS and LLP rate tariffs have demand charges and in 2016, 5 of the 15 customers taking service on TEP LLP rate tariffs and 41 of the 561 customers taking service on TEP LGS rate tariffs are subscribed to the Company's NEM Rider R-4.

VIII. RESPONSE TO RUCO'S TESTIMONY.

Q. Have you reviewed the rate design testimony submitted by RUCO?

A. Yes, I have reviewed the rate design testimony submitted by RUCO witnesses Lon Huber and Frank Radigan.

Q. On page 15 of his rate design testimony Mr. Radigan states that the Company's provision of hourly load data for 1,600 residential customers in response to RUCO

[51] Garrett Direct, 8:17.

DR 7.11 was useless because it provides no statistically reliable data to measure load by usage. Please comment.

A. I am not sure I fully understand Mr. Radigan's criticism. First, TEP provided a statistically sound random sample of over 17,000 residential load profiles in response to RUCO DR 7.11, not 1,600 as Mr. Radigan states. Second, while TEP did not provide a "typical" hourly residential load profile, the Company did provide monthly summaries of these load profiles by percentile groupings.[52]

Second, I don't quite understand what Mr. Radigan means by his criticism that "this data is useless as it provides no statistically reliable data to measure load by usage."[53] If by measuring "load by usage" Mr. Radigan means that he would like to see summaries of peak demands at different customer usage levels, the aforementioned files that TEP submitted provide exactly that. If he means something else, I am at a loss to determine what that might be.

Q. On pages 15 and 16 of his rate design testimony, Mr. Radigan states that the Company's sampling could not be reliable because it did not use stratification in its sampling. Does the Company agree with this characterization?

A: The characterization is incorrect. Mr. Radigan is confused about the sample sizes used by the Company and contradicts himself in his own testimony where he provides a graph that shows data for 3,000 TEP residential customers but also asserts that the Company provided a spreadsheet with only 1,600. The truth is that neither of these are correct and, as I mentioned above TEP's response to the data request that Mr. Radigan specifies in his testimony actually contained load profiles for over 17,000 residential customers. Furthermore, as I discussed in Section II of my testimony, the Company actually used a

[52] See Excel file "TEP 2015 RES Load-PV Data.xlsx", which was submitted with TEP's Supplemental Response to UDR 1.001 dated December 1, 2015.

[53] Direct Testimony of Frank Radigan ("Radigan"), 15:16-17.

sample of 14,186 residential customers for the residential three-part rate design and bill analyses in its Application.

In addition to the confusion related to the sample size used by the Company, which was available to him, Mr. Radigan is mistaken about how sampling must be done to make accurate predictions about a population. Mr. Radigan claims that "To be reliable, a stratification of customers by monthly usage must be developed, a statically [sic] significant sample would then have to be selected for each strata [sic] and hourly load data collected and then extrapolated to get a meaningful typical load pattern for a customer type."[54] Perhaps in the past, when processing large hourly data sets was incredibly difficult, stratified sampling could be useful to limit the burden of data processing. Today, stratification is unnecessary with the ability to acquire and process large hourly data sets. The Company's very large random sample, in this case over 4 percent of test-year residential customers, which matches well to the overall population, was beyond sufficient for the modeling the Company performed.

Q. On page 16 of his rate design testimony, Mr. Radigan states that "As it is, one cannot verify that the peak demand, as reported by the Company and used as an input into its cost of service study, is anywhere near accurate."[55] Please comment.

A. The fact that TEP did not produce any "typical" residential hourly load profiles has absolutely nothing to do with the peak demand data that are used as inputs to the Company's cost of service study. The Company's CCOSS uses as inputs alternative measures of peak demand and energy usage at the customer class level and in no way depends on typical customer hourly load profiles.

[54] Radigan Rate Design Direct, 15:17 – 16:1-3.
[55] Radigan Rate Design Direct, 16:3-5.

Finally, I am at a loss to follow how Mr. Radigan goes directly from this criticism of the Company's load profile data and CCOSS to the position that "As to the partial requirements customer, the lack of presentation provides little basis to support the price signals a 24/7 demand charge would send."[56] As I explained in detail in Section II of my testimony, the Company's three-part rate analyses presented in this case for both full and partial requirements customers were performed using samples of hourly load profiles for over 14,000 TEP residential and over 5,000 TEP SGS customers.

Q. Does this conclude your testimony?

A. Yes.

[56] Radigan Rate Design Direct, 16:7-9.

Exhibit RDB-R-1

Original tables presented on pages 21, 25, and 29 of the Direct Testimony of TEP witness Dallas Dukes.[1]

Table 1: Residential Bill Comparisons from Dukes Direct Testimony, page 21

Monthly Usage	RES[2] Full Requirements Service	RES 2-part Rate with Net Metering: Banking Excess kWh	RES 2-part Rate with Net Metering: TEP Purchases Excess kWh[3]
500 kWh per Month			
Monthly Non-Fuel Cost Recovery	$50.74	$20.00	$41.13
Average Monthly Bill (pre-tax)	$74.16	$23.42	$37.70
Unrecovered Non-Fuel Costs	NA	$30.74	$9.61
Monthly Bill Savings	NA	$50.74	$36.46
900 kWh per Month			
Monthly Non-Fuel Cost Recovery	$81.20	$20.16	$51.02
Average Monthly Bill (pre-tax)	$120.86	$23.61	$44.69
Unrecovered Non-Fuel Costs	NA	$61.04	$30.18
Monthly Bill Savings	NA	$97.25	$76.17
1,200 kWh per Month			
Monthly Non-Fuel Cost Recovery	$104.92	$20.00	$60.36
Average Monthly Bill (pre-tax)	$156.54	$23.42	$51.66
Unrecovered Non-Fuel Costs	NA	$84.92	$44.56
Monthly Bill Savings	NA	$133.12	$104.88
1,500 kWh per Month			
Monthly Non-Fuel Cost Recovery	$128.65	$20.11	$62.52
Average Monthly Bill (pre-tax)	$192.10	$23.54	$53.30
Unrecovered Non-Fuel Costs	NA	$108.54	$66.13
Monthly Bill Savings	NA	$168.56	$138.80

[1] For data and supporting analysis, see Excel file "2015 TEP R-01 Demand-PRS.xlsx", which was submitted with TEP's Supplemental Response to UDR 1.001 dated December 1, 2015.
[2] Original tables labeled "R-01"; TEP is proposing to rename the rate class "RES".
[3] All TEP purchases of excess DG kWh output are calculated on an hourly basis; DG customers are compensated in the form of bill credits at TEP's proposed Renewable Credit Rate of $0.0584/kWh.

Table 2: Residential Bill Comparisons from Dukes Direct Testimony, page 25

Average Monthly Usage	Average Monthly Load Factor	Average Monthly Bill (pre-tax)		
		RES	RES-D	Difference
500 kWh	18.4%	$74.16	$83.51	$9.35
900 kWh	23.3%	$120.86	$121.33	$0.47
1,200 kWh	26.7%	$156.54	$147.29	($9.25)
1,500 kWh	31.5%	$192.10	$169.45	($22.65)

Table 3: Residential Bill Comparisons from Dukes Direct Testimony, page 29

Monthly Usage	RES Full Requirements Service	RES 2-part Rate with Net Metering: TEP Purchases Excess kWh[4]	RES-D 3-part Rate with Net Metering: TEP Purchases Excess kWh
500 kWh per Month			
Monthly Non-Fuel Cost Recovery	$50.74	$41.13	$55.92
Average Monthly Bill (pre-tax)	$74.16	$37.70	$52.65
Unrecovered Non-Fuel Costs	NA	$9.61	-$5.18
Monthly Bill Savings	NA	$36.46	$21.51
900 kWh per Month			
Monthly Non-Fuel Cost Recovery	$81.20	$51.02	$71.09
Average Monthly Bill (pre-tax)	$120.86	$44.69	$64.99
Unrecovered Non-Fuel Costs	NA	$30.18	$10.11
Monthly Bill Savings	NA	$76.17	$55.87
1,200 kWh per Month			
Monthly Non-Fuel Cost Recovery	$104.92	$60.36	$80.40
Average Monthly Bill (pre-tax)	$156.54	$51.66	$71.94
Unrecovered Non-Fuel Costs	NA	$44.56	$24.52
Monthly Bill Savings	NA	$104.88	$84.60
1,500 kWh per Month			
Monthly Non-Fuel Cost Recovery	$128.65	$62.52	$83.91
Average Monthly Bill (pre-tax)	$192.10	$53.30	$74.93
Unrecovered Non-Fuel Costs	NA	$66.13	$44.74
Monthly Bill Savings	NA	$138.80	$117.17

[4] All TEP purchases of excess DG kWh output are calculated on an hourly basis; DG customers are compensated in the form of bill credits at TEP's proposed Renewable Credit Rate of $0.0584/kWh.

Exhibit RDB-R-2

Updated versions of the tables that were presented on pages 21, 25, and 29 of the Direct Testimony of TEP Witness Dallas Dukes with the following changes[1]:

- Modeling enhancements and revisions summarized in Section II of rebuttal testimony.
- Based on the random sample of 17,270 residential hourly load profiles that TEP submitted in response to RUCO DR 7.11; 16,963 total observations were used after editing the sample.

Table 1a: Updated Residential Bill Comparisons from Dukes Direct Testimony, page 21

Monthly Usage	RES: Full Requirements Service	RES: DG, Current NEM	RES: DG, Bill Credit[2] for Hourly Exports
500 kWh per Month			
Monthly Non-Fuel Cost Recovery	$50.75	$20.00	$37.60
Average Monthly Bill (pre-tax)	$75.47	$23.86	$36.27
Unrecovered Non-Fuel Costs	NA	$30.75	$13.15
Monthly Bill Savings	NA	$51.61	$39.19
900 kWh per Month			
Monthly Non-Fuel Cost Recovery	$81.18	$20.00	$51.91
Average Monthly Bill (pre-tax)	$121.82	$23.45	$46.25
Unrecovered Non-Fuel Costs	NA	$61.18	$29.27
Monthly Bill Savings	NA	$98.37	$75.57
1,200 kWh per Month			
Monthly Non-Fuel Cost Recovery	$104.93	$20.00	$64.57
Average Monthly Bill (pre-tax)	$157.52	$22.89	$55.58
Unrecovered Non-Fuel Costs	NA	$84.92	$40.36
Monthly Bill Savings	NA	$134.64	$101.95
1,500 kWh per Month			
Monthly Non-Fuel Cost Recovery	$128.66	$20.00	$76.88
Average Monthly Bill (pre-tax)	$193.15	$22.62	$64.86
Unrecovered Non-Fuel Costs	NA	$108.65	$51.78
Monthly Bill Savings	NA	$170.53	$128.30

[1] For data and supporting analysis, see Excel file "2015 TEP R-01 Demand-PRS_rdb-r2.xlsx", which is being submitted with TEP's workpapers.
[2] All bill credits are calculated at TEP's proposed Renewable Credit Rate of $0.0584/kWh.

Table 2a: Updated Residential Bill Comparisons from Dukes Direct Testimony, page 25

Average Monthly Usage	Average Monthly Load Factor	Average Monthly Bill (pre-tax)		
		RES	RES-D	Difference
500 kWh	18.9%	$75.47	$83.68	$8.21
900 kWh	23.2%	$121.82	$121.81	($0.01)
1,200 kWh	25.2%	$157.52	$150.50	($7.02)
1,500 kWh	26.8%	$193.15	$180.85	($12.30)

Table 3a: Updated Residential Bill Comparisons from Dukes Direct Testimony, page 29

Monthly Usage	RES: Full Requirements Service	RES: DG, Bill Credit[3] for Hourly Exports	RES-D: DG, Bill Credit for Hourly Exports
500 kWh per Month			
Monthly Non-Fuel Cost Recovery	$50.75	$37.60	$53.18
Average Monthly Bill (pre-tax)	$75.47	$36.27	$52.11
Unrecovered Non-Fuel Costs	NA	$13.15	-$2.43
Monthly Bill Savings	NA	$39.19	$23.36
900 kWh per Month			
Monthly Non-Fuel Cost Recovery	$81.18	$51.91	$69.34
Average Monthly Bill (pre-tax)	$121.82	$46.25	$63.97
Unrecovered Non-Fuel Costs	NA	$29.27	$11.84
Monthly Bill Savings	NA	$75.57	$57.85
1,200 kWh per Month			
Monthly Non-Fuel Cost Recovery	$104.93	$64.57	$82.24
Average Monthly Bill (pre-tax)	$157.52	$55.58	$73.54
Unrecovered Non-Fuel Costs	NA	$40.36	$22.69
Monthly Bill Savings	NA	$101.95	$83.99
1,500 kWh per Month			
Monthly Non-Fuel Cost Recovery	$128.66	$76.88	$95.45
Average Monthly Bill (pre-tax)	$193.15	$64.86	$83.73
Unrecovered Non-Fuel Costs	NA	$51.78	$33.21
Monthly Bill Savings	NA	$128.30	$109.42

[3] All bill credits are calculated at TEP's proposed Renewable Credit Rate of $0.0584/kWh.

Exhibit RDB-R-3

SOLON CORPORATION'S RESPONSE TO TUCSON ELECTRIC POWER'S SECOND SET OF DATA REQUESTS
DOCKET NOS. E-01933A-15-0239 & E-01933A-15-0322

TEP 2.02 On page 9, lines 12-14 of Mr. Seibel's Direct Testimony, with respect to analysis of the impacts of the Company's rate design proposals, Mr. Seibel states that "I recommend at least 30% of each rate class be represented, with the selected customers evenly dispersed between the minimum and maximum load factor for each rate class."

a. Is Mr. Seibel recommending a sample size of 30% for each rate class on which to perform bill impact analyses or that TEP present bill impacts for 30% of the customers in each rate class?

b. If Mr. Seibel is recommending a sample size of 30% of the customers in each rated class, please provide all calculations and analyses Mr. Seibel used obtain the 30% sample size.

c. If Mr. Seibel is recommending a sample and that the sample contain "selected customers evenly dispersed between the minimum and maximum load factor for each rate class," does that mean Mr. Seibel is recommending a random sample of customers stratified by load factor or that he is not recommending that the sample be random?

RESPONSE:

a. SOLON recommends that TEP provide interval load data, in the smallest time interval available but at a minimum in an hourly interval, in the same format as provided in the Excel file named "RUCO 7.11 Individual Customer Sample-Confidential.xlsx."

b. Below is one path to arrive at a sample set:

Step 1: Separate all data by customer class, specifically Residential, Commercial, and Industrial.

Step 2: Separate the data in each customer class into equally sized bins based on load factor. For example, if TEP has approximately 350,000 residential customers, each bin would hold approximately 35,000 customers. The first bin would be all residential customers in the $1^{st} - 10^{th}$ percentile of annual load factor. The second bin would be all residential customers in the $11^{th} - 20^{th}$ percentile of annual load factor. This would continue for the remaining eight bins and the other two rate classes.

Step 3: Randomly select 30% of the customers within each bin and log the 24 month load profile in the same general format as TEP provided excel file named "RUCO 7.11 Individual Customer Sample-Confidential.xlsx." Each "bin" would be its own sample set.

One method for taking a sample from a larger data set uses the terms "confidence level" and "confidence interval". Using a 99% confidence level and a 1% confidence interval, for each 35,000 sample set, you arrive at a sample size of 11,279, or 32% (http://www.surveysystem.com/sscalc.htm).

SOLON simply recommended "**at least** 30%." Given the significant rate design proposals by TEP, SOLON believes it is in TEP's interest to know how its proposals will

SOLON CORPORATION'S RESPONSE TO TUCSON ELECTRIC POWER'S SECOND SET OF DATA REQUESTS
DOCKET NOS. E-01933A-15-0239 & E-01933A-15-0322

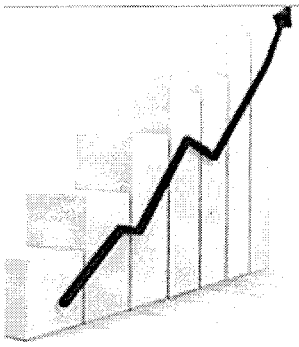
affect all of its customers and believes TEP should release all customer interval load data. If TEP believes this analysis to be overly burdensome, SOLON has the ability to complete this analysis in a timely fashion, and SOLON is happy to assist TEP with this analysis.

c. See previous response for this request.

RESPONDENT:
Brian Seibel

WITNESS:
Brian Seibel

Exhibit RDB-R-4



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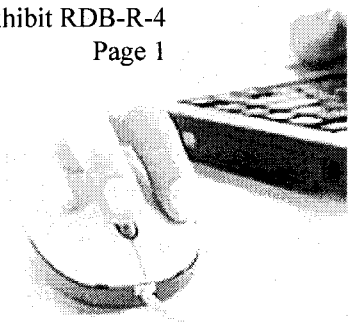

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Before using the sample size calculator, there are two terms that you need to know. These are: **confidence interval** and **confidence level**. If you are not familiar with these terms, click here. T learn more about the factors that affect the size of confidence intervals, click here.

Enter your choices in a calculator below to find the sample size you need or the confidence interv you have. Leave the Population box blank, if the population is very large or unknown.

Determine Sample Size

Confidence Level: ○ 95% ● 99%
Confidence Interval: 1
Population: 375000
Calculate Clear
Sample size needed: 15934

Find Confidence Interval

Confidence Level: ● 95% ○ 99%
Sample Size:
Population:
Percentage: 50
Calculate Clear
Confidence Interval:

Exhibit RDB-R-5

SOLON 3.1

In the file "2015 TEP R-01 Demand-PRS.xlsx," there are references throughout the Load_PV Mean, Load_PV Median, Load_PV XS, Load_PV SM, Load_PV MED, Load_PV LG, Load PV XL tabs to a "2014 Res Avg Hourly Profile," "2014 Solar Billing Dets," and "PV kwh/kBh Data." These references are located in cells L58:L8817, E37:F48, and K37:M48, respectively. Please provide the complete data set these values from which were derived in Microsoft Excel format, unlocked, and with formulas intact. To clarify, and as an example, in sheet "Load_PV XS," the 2014 Solar Billing Dets is referenced as the 10th percentile, and the 2014 Res Avg Hourly Profile is referenced as the 25th percentile. This indicates a larger data set was used to arrive at these profiles, and we are seeking the complete data set used.

RESPONSE:

The Excel file "TEP 2015 RES Load-PV Data.xlsx", which was provided with TEP's Supplemental Response to UDR 1.001 dated December 1, 2015, contains all of the raw data from which the customer load characteristics in "2015 TEP R-01 Demand-PRS.xlsx" (i.e., "2014 Res Avg Hourly Profile," "2014 Solar Billing Dets," and "PV kwh/kBh Data" identified in the question) were derived.

The values for the "2014 Res Avg Hourly Profile" were drawn from the file tab in "TEP 2015 RES Load-PV Data.xlsx" titled "TY2015 Hrly Data" and those for "2014 Solar Billing Dets" and "PV kwh/kBh Data" from the tab titled "TY20015 Load-PV Bins". The raw data set underlying these customer load characteristics was derived from a random sample of 14,186 TEP R-01 customers and appears in the file tab titled "TY2015 Raw Data". All percentiles referenced in "2015 TEP R-01 Demand-PRS.xlsx" correspond to groupings of data as they appear in "TEP 2015 RES Load-PV Data.xlsx".

Please note that TEP provided revised versions of these files as supplements to UDR 1.001 on June 6, 2016. The filenames for the revised files are "2015 TEP R-01 Demand-PRS_rev 06-03-16.xlsx" and "TEP 2015 RES Load-PV Data_rev 06-03-16.xlsx". The raw data contained in "TEP 2015 RES Load-PV Data.xlsx" and "TEP 2015 RES Load-PV Data_rev 06-03-16.xlsx" are identical and the explanation provided above applies.

RESPONDENT:

Greg Strang / Rick Bachmeier

WITNESS:

Craig Jones

SOLON 3.2

In the file "2015 TEP GS-10 Demand-PRS.xlsx," there are references throughout the Load_PV Mean, Load_PV Median, Load_PV XS, Load_PV SM, Load_PV MED, Load_PV LG, Load PV XL tabs to a "2014 Res Avg Hourly Profile," "2014 Solar Billing Dets," and "PV kwh/kBh Data." These are located in cells L58:L8817, E37:F48, and K37:M48, respectively.

a. Please provide the complete data set from which these values were derived in Microsoft Excel format, unlocked, and with formulas intact. For example, in sheet "Load_PV XS," the 2014 Solar Billing Dets is referenced as the 30th percentile, and the 2014 Res Avg Hourly Profile is referenced as the 50th percentile. This indicates a larger data set was used to arrive at these profiles, and we are seeking the complete data set used.

b. If TEP's data set used in this Excel file assumes a number of their current GS-10 customers would be switched to a different rate plan under the proposal, and those profiles are excluded from the data set, please provide the profiles for all customers assumed to be switched to a different rate plan in a separate file.

RESPONSE:

a. The Excel file "TEP 2015 SGS Load-PV Data.xlsx", which was provided with TEP's Supplemental Response to UDR 1.001 dated December 1, 2015, contains all of the raw data from which the customer load characteristics in "2015 TEP GS-10 Demand-PRS.xlsx" (i.e., "2014 Res Avg Hourly Profile," "2014 Solar Billing Dets," and "PV kwh/kBh Data" identified in the question) were derived. Please note that any references or titles containing "Res" in this file are mislabeled and should be interpreted as "GS-10."

   The values for the "2014 Res Avg Hourly Profile" were drawn from the file tab in "TEP 2015 SGS Load-PV Data.xlsx" titled "TY2015 Hrly Data" and those for "2014 Solar Billing Dets" and "PV kwh/kBh Data" from the tab titled "TY20015 Load-PV Bins". The raw data set underlying these customer load characteristics was derived from a random sample of 6,251 TEP GS-10 customers and appears in the file tab titled "TY2015 Raw Data". All percentiles referenced in "2015 TEP GS-10 Demand-PRS.xlsx" correspond to groupings of data as they appear in "TEP 2015 SGS Load-PV Data.xlsx".

b. The raw data set in the Excel file "TEP 2015 SGS Load-PV Data.xlsx" represents a sample of TEP's existing GS-10 customers at the time the sample was drawn. No observations were excluded based on assumptions about customers switching to other rate plans.

RESPONDENT:

Greg Strang / Rick Bachmeier

WITNESS:

Craig Jones

Rebuttal Testimony of

Denise A. Smith

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

REBUTTAL TESTIMONY OF

DENISE A. SMITH

ON BEHALF OF

OF TUCSON ELECTRIC POWER COMPANY

JULY 25, 2016

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Denise A. Smith and my business address is 88 East Broadway, Tucson, Arizona, 85701.

Q. Did you submit Direct Testimony on behalf of Tucson Electric Power Company ("TEP" or "Company") in this Docket?

A. Yes.

Q. Have you reviewed the Direct Testimonies filed by the Utilities Division ("Staff") of the Arizona Corporation Commission ("Commission"), the Arizona Community Action Association ("ACAA"), Southwest Energy Efficiency Project ("SWEEP"), the Residential Utility Consumer Office ("RUCO"), and International Brotherhood of Electrical Workers Local 1116 ("IBEW")?

A. Yes, I have.

Q. What subject matter do you cover in your Rebuttal Testimony?

A. I address: (1) the positions of Staff regarding the proposed changes to the Company's Rules and Regulations ("Rules"), the Company's request to be relieved from certain compliance requirements, explain the Company's additional customer energy education plans, and the Company's proposed Prepay program; (2) the concerns raised by the ACAA regarding Lifeline customer deposits, the Lifeline discount rate, modifications to termination notices, bill assistance and the Company's proposed Prepay program; (3) the concerns raised by SWEEP regarding Energy Efficiency ("EE") and the Company's proposed Prepay program; (4) the concerns raised by RUCO regarding credit card

processing; (5) IBEW's position on call center staffing; and (6) the need for an additional proposed modification to the Rules.

II. RESPONSE TO STAFF.

A. Rules and Regulations.

Q. Do you agree with Staff witness Candrea Allen's recommendations regarding the proposed changes to the Rules?

A. The Company agrees to the following Staff recommendations without modification:

- To leave the words, "more than" in Subsection 3.B.1.a.
- Adding language to the end of Subsection 4.A.6. that states, "This charge will apply for each interval history request made or when Customers request their consumption history more than once in a 12-month period." Staff's recommendations will also be reflected in the Statement of Charges.
- Adding language to the end of Subsection 10.H. that states, "For Customers who choose to not have an automated meter installed or wish to replace an automated meter with a non-transmitting meter, the Special Meter Reading Fee set forth as Fee No. 3 in the Company's Statement of Charges will be a monthly recurring charge. The Automated Meter Opt-Out Set-Up Fee set forth as Fee No. 8 will only apply to those Customers who request the removal of an automated meter." Staff's recommendations will also be reflected in the Statement of Charges.
- Adding language to the end of Subsection 11.I.6. that states, "listed as Fee No. 15 in the Statement of Charges."
- Adding "by the Company or its Agent" to the end of Subsection 11.L.2.

Q. Please comment on Subsection 12.H. of the Rules.

A. In the UNS Electric, Inc. ("UNSE") rate case,[1] UNSE ultimately withdrew its request to add Subsection 12.H. to the UNSE Rules. Similarly, the Company wishes to withdraw its request to add Subsection 12.H. to the TEP Rules. Staff indicated it had no objection to this withdrawal.

B. <u>Prepay Program.</u>

Q. Do you agree with Staff witness Matt Connolly's recommendation to offer the Prepay program as a pilot program?

A. Yes.

Q. Please respond to Staff witness Matt Connolly's testimony wherein he does not believe TEP's Prepay program should be included as part of TEP's EE Implementation Plan.

A. The Company respectfully disagrees and intends to file for a Prepay EE program in 2016 to be included in its EE portfolio. The Company firmly believes the disconnection that occurs when a customer does not fund their account is separable from "the conservation of energy by end-use customers" that occurs when customers opt for more control of their energy budget. The daily view of energy use that customers receive with a Prepay option is a powerful behavioral EE program, as it can produce a greater awareness of daily energy consumption, allowing the customer to modify their energy usage as they deem appropriate. Without approval as an EE program, economic justification of those tools would be more difficult to make them available to customers. Traditional behavioral EE programs save 1-2% and have proven to be cost effective; therefore, Prepay programs should be even more cost effective since they have proven to save around 4-12%. While

[1] Docket No. E-04204A-15-0142.

Prepay is a billing option, it is equally as powerful as an energy management tool since it provides constant feedback; making the cost of energy consumption tangible in real time as opposed to monthly in arrears. The opportunity to implement prepayment programming to achieve cost-effective EE savings will go unrealized without approval of the Prepay program as an EE program.

Q. Staff witness Matt Connolly then states that a Prepay program would not qualify as an EE program under the Commission's current Electric Energy Efficiency Rules. Does the Company agree?

A. No. In fact, as explained above, this type of program can produce a greater awareness of daily energy consumption, allowing the customer to modify their behavior. This could potentially result in greater saving for customers than other types of behavioral EE programs. A behavioral EE program is defined as conservation that recognizes that a customer's energy choices are influenced by social and psychological behavior. A prepay program, like a Home Energy Report program, gives customers feedback along with other EE advice and information about their energy use in order to reduce consumption through conservation. Prepay is a superior feedback tool as the energy information on household usage is provided more frequently, daily, rather than once a month or every other month, as is the case with Home Energy Reports. It therefore meets the Commission's definition of a conservation program under the Arizona Administrative Code ("A.A.C.") R-14-2-2401 ("the production or delivery of an equivalent level and quality of end-use electric service using less energy, or the conservation of energy by end-use customer").

Q. Has this Commission ever approved behavioral EE programs?

A. Yes. The Commission has approved behavioral EE programs for all three of the major Arizona electric utilities, APS, TEP and UNS Electric. In fact, the Commission recently

ordered both UNS Electric[2] and TEP[3] to implement a Home Energy Reports program, if cost-effective.

Q. Do you agree with Staff witness Matt Connolly's recommendation to offer the Prepay program to customers on the Lifeline tariff?

A. Yes. Company witness Mr. Craig Jones addresses this addition to the Lifeline tariff further in his Rebuttal Testimony.

Q. Do you agree with Staff witness Matt Connolly's recommendation to add information on balance alerts and thresholds to Section 13 of the Prepay Service Agreement?

A. Yes. Because the program technology will require over 12 months to implement from the date of approval, the Company will submit a final version of the Service Agreement to Staff prior to publicly launching the program.

Q. Do you agree with Staff witness Matt Connolly's recommendation to eliminate Section 20 of the Prepay Service Agreement which discusses the closing of accounts?

A. No. Because there are non-disconnect periods such as weekends and holidays, it will be possible for a customer to accrue a negative balance before disconnection occurs. In addition, customers will accrue a negative balance during any disconnection grace period provided within the program.

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[2] Decision No. 75297 (October 27, 2015).
[3] Decision No. 75450 (February 11, 2016).

Q. Do you agree with Staff witness Matt Connolly's recommendation at page 9, line 22 of his direct testimony, to add language to the Prepay Service Agreement that the customer could be subject to an additional per payment convenience fee?

A. Yes. For example, a customer who chooses to pay their Prepay account by walking into a Walmart Payment Center will still be subject to the $1.00 convenience fee each time they chose to pay on their account.

C. <u>Compliance Requirements.</u>

Q. Do you agree with Staff witness Matt Connolly's recommendations regarding the 12 Compliance Items listed in Exhibit DAS-3 of my direct testimony?

A. Yes.

D. <u>Other Staff Recommendations.</u>

Q. Do you agree with the recommendation of Staff witness Eric Van Epps that recommends updating the Company's DSM Plan of Administration ("POA") so that it is consistent with all existing Commission decisions?

A. Yes. The Company agrees to file a DSM POA in my Rejoinder Testimony.

Q. Please respond to Staff witness Donna Mullinax's testimony regarding credit card processing fees.

A. Parties in this case, including Staff, do not support the Company's request to include a portion of credit card fees charged to provide this common service to our customers in the Company's base rates. The Company therefore withdraws this request and will continue to charge the participating customers based on the cost incurred to provide the

service. The impact on the revenue requirement is addressed in Mr. David Lewis' Rebuttal Testimony.

Q. Staff witness Howard Solganick discusses how utilities could convey energy information to customers on page 8 of his Direct Testimony. Could you describe TEP's efforts to provide customers with more information about their usage?

A. The Company is planning a multi-staged, multi-channel approach to supporting customers' information needs according to their preferred communications channel including through paper mailing, electronic (email) delivery, and/or telephonic Interactive Voice Response ("IVR") system. In late summer of this year, the Company will add another channel by launching a customer application supporting mobile access to account related data and messaging on cellular or WiFi enabled Apple and Android devices. Supporting customers' understanding of their energy usage will require new tools and programming that leverage the Company's existing platforms. The Company is in various stages of evaluating and implementing modifications to existing platforms and rolling out new customer programs and tools which include: (1) existing and enhanced "My Account" web portal in which customers can sign on and view monthly usage and billing and complete a home energy audit; (2) a display of hourly interval data where a customer will be able to view their kWh and kW consumption by the hour, day, week, and month on web and mobile devices; (3) an e-bill/paper bill re-design that shows customers more energy information, including demand; (4) Home Energy Reports comparing usage to neighbors (similar to Mr. Solganick's description on page 8 of his direct testimony); and (5) requesting approval of a Prepay program in this rate case.

III. RESPONSE TO ACAA.

Q. Do you agree with the ACAA's recommendations to keep the deferred payment plan at six months?

A. Yes. In the UNSE rate case, UNSE ultimately withdrew its request to change the amount of monthly installments of the deferred payment plan from six months to three months in Subsection 11.I.2.c. Therefore, in an effort to keep the Rules of TEP and UNSE consistent, the Company withdraws this requested change.

Q. Do you agree with the ACAA's recommendations to add bill assistance and other related information to the disconnect notice?

A. Yes. The Company supports Ms. Zwick's request to add information to our disconnect notices notifying customers of agencies providing bill assistance opportunities in their area as well as information about weatherization agencies and the Lifeline discount. However, adding such information to the current disconnect notice format presents challenges, including space and other limitations given the Company's billing system. Therefore, as part of its upcoming bill/letter redesign project plan, the Company is making plans to include the information on a bill insert with the disconnect notice sent to such customers.

Q. Do you agree with the ACAA's recommendation that Lifeline customers be exempt from TEP's proposed modification to the Rules regarding deposits?

A. No. Establishment or re-establishment of deposits occurs when customers demonstrate a repeated failure to pay their bill, or evidence is produced suggesting an increase in the probability that a customer will not pay. If/when certain factors make it challenging for a customer to pay a bill and/or deposit, it is brought to the Company's attention and every attempt is made to provide a workable solution. These solutions may include referrals to

assistance agencies, payment arrangements, or simply granting extra time. The Company has a long-standing history of working directly with individual customers to help them successfully meet their payment obligations. In 2015, the Company granted 287,178 payment extensions to customers based on stated need.

Q. Do you agree with the ACAA's recommendation regarding not requiring a deposit when a customer files bankruptcy?

A. No. Subsection 3.B.3. of the Rules is consistent with the approved Rules of other Arizona utilities. A deposit on a post-petition account is an appropriate assurance of payment under 11 U.S.C. § 366.

Q. Does the Company support automatically enrolling customers in the Lifeline program who receive bill assistance?

A. While the Company is not opposed to increasing the number of Lifeline participants, it is opposed to setting a precedent of enrolling customers in a tariff unsolicited and without their express consent. The Company will make every effort to keep agencies supplied with Lifeline enrollment pamphlets they can provide to all qualifying assistance recipients.

Q. Does TEP have a comprehensive outreach marketing program to promote its Lifeline rates?

A. Yes. The Company's Customer Service Representatives are trained to offer Lifeline program information, when appropriate, to customers who express an inability to pay their bill. Customers may be directed to the Company's website for enrollment information, or will be mailed an enrollment pamphlet. Additionally, the Company runs Lifeline informational campaigns throughout the Company's service area which include:

bill inserts, radio and newspaper advertising, social media posts, and stories in the Company's quarterly e-newsletter "Plugged In".

Q. Does the Company agree with ACAA's request to increase the funding of TEP's current Bill Assistance program from $150,000 to $200,000?

A. The Company believes that its shareholder contribution of $150,000 annually to the Bill Assistance program is reasonable.

Q. Do you agree with ACAA's testimony regarding TEP's Prepay program on pages 14-27?

No. The Company disagrees with much of the testimony as the information presented from the referenced studies was selective and in many cases did not reflect important conclusions of the referenced work. In addition, many of ACAA's conclusions are speculative or interpretive in nature. The Company is amenable to implementing the program under pilot status to study such items as customer satisfaction, program energy, demand savings, customer interest and other information. The Company also notes that participation in the Prepay program is voluntary.

In addressing specific ACAA concerns regarding Prepay programs, it is helpful to consider the key concepts behind offering prepayment as a billing option: (1) the program's direct cause and effect structure enables customers to have more control over their spending habits in the same manner that people often choose to utilize cash or debit cards versus credit cards; (2) a billing option that more closely aligns when customers pay for energy with when they consume it assists customers in making proactive choices about how much energy they purchase; and (3) customers who commit to prepaying for their energy are necessarily relieved from posting a deposit because there is theoretically less risk of an unpaid arrearage.

Q. Does the Company intend to claim EE savings resulting from the program, and if so will disconnections be removed from the reported EE savings?

A. Yes. The Company intends to file an EE program associated with the Prepay option and the Company will certainly remove the impact of disconnections from the reported savings, as other studies have done. Prepay, is, in fact, a powerful behavioral EE program in which customers can reduce their energy consumption through a series of behavioral changes leading to conservation. During this rate case the Company is requesting approval of the tariff(s) upon which to build the program and then, as a second step, it will seek approval of the Prepay program as an EE measure in the Company's behavioral program through its EE Implementation Plan docket.

Studies at SRP, APS, Oklahoma Electric Cooperative and other utilities indicate prepayment programs result in conservation savings when disconnections are removed, and in fact, provide customer satisfaction. While ACAA may not agree with the findings presented in those studies, ACAA will have the opportunity to participate in the formative discussion as to the methodology to be used to measure and verify the savings from this program as part of the EE program review process. The below table outlines some key program statistics from a sampling of Prepay programs across the country.[4]

[4] Sources for the table are: "Paying Upfront: A Review of Salt River Project's MPower Prepaid Program." EPRI, October 2010; "Demand Side Management Residential Prepaid Energy Conservation Pilot Program: End of Pilot Report." Arizona Public Service Company, January 2015; "The Effect of Prepayment on Energy Use." Michael Ozog, PhD, March 2013; "Summary Findings Northwest Utility Prepay Study." DEFG, April 2014; "Prepaid Metering Program Study in the Tennessee Valley." Tim Hennessy, Deborah Olisky, April 2016.

Reported Results Among Utility Prepay Programs

Utility	SRP	APS*	Oklahoma Electric Coop.	Glacier	Peninsula Light*	TVA
State	AZ	AZ	OK	MT	WA	Multiple
# residential Customers	830,000	1,200,000	50,000	5,100	30,000	177,846
Prepay Participation	100,000	2,000	7,000	1,250	170	9,062
Start Date	1993	2012 2 year Pilot	2006	2009	Pilot 2013	Various
Savings measured and verified	12.0%	7.5%	11.0%	14.0%	5.5%	5%-11.7%***
Satisfied with Prepay program	>83%	71%/78%**	Not measured	93.0%	86.0%	Not measured
Changed energy usage behavior since enrolling in Prepay	No Data	72%/79%**	85.0%	80.0%	64.0%	Not measured

*indicates program pilot (Participation in APS' pilot program was limited to 2,000 customers)

**reflects two survey waves

***varied across 6 participating TVA utilities

Q. Do you agree with Ms. Zwick's characterization that customers using the prepayment billing option receive "second class service"?[5]

A. Absolutely not. Customers that choose this billing option would receive the same safe, reliable electrical service as all other customers. In fact, prepayment customers receive enhanced service including interactive daily feedback, the waiver of deposit and reconnection fees, and access to initiate immediate reconnection should they trigger a disconnection, among other benefits.

Q. Should Prepay customers receive discounted fees and service rates?

A. No. The cost of providing Prepay service has additional costs in the form of more expensive meters and additional software and communication costs.

[5] Direct Testimony of Cynthia Zwick, page 15:1.

Q. Why was the grace period set at four hours and not a longer period?

In the context of the program, the term "grace period" is just the final step in a lengthy disconnection protocol that begins with several low balance alerts delivered to the customer through the customer's selected mode of communication. The actual time from accruing a zero balance to true disconnection will range from 14-38 hours depending on when an individual account runs out of funds. This period could be longer if the customer's funds are depleted during a weekend or holidays. During the grace period customers will received a series of alerts through their preferred method of communication.

Q. Should customers who disconnect frequently be allowed to continue to participate in this program?

A. Yes. Participation in the program is always at the customer's discretion and customers should not be denied that choice. Frequent disconnection does not necessarily indicate a customer does not have the funds to pay for their energy, rather the customer may not prioritize the service until disconnection occurs. This is supported by the fact that in studied programs, most disconnections are reconnected within two hours, suggesting resources to pay for power are ultimately on hand.

Were a customer to truly exhaust all means of paying for their electrical consumption Prepay enables them to reconnect immediately with no fees, and no deposit. This is in contrast to the process under standard billing whereby the customer would be required to pay $32 for next-day reconnection or $57 for same-day reconnection in addition to posting and maintaining a deposit.

Q. Will the Company target low income customers for subscription to this billing option?

A. No. Because prepayment mitigates the risk of default and non-payment, there is no need for a deposit. Because there is no deposit required, this program will be attractive to customers who want to firmly manage their energy use, mobile customers, including students, part-time residents, temporary workers, and other customers who may be facing deposit requirements from their landlord or other utilities.

Q. Do you have any comment on Ms. Zwick's citation of EPRI's report noting that M-Power turnover rate was "relatively high"?

A. Yes. Ms. Zwick's testimony cites only selective portions of the EPRI report which lead the reader to the false conclusion that SRP's prepaid program has a 1-2 month turnover. The study actually shows a 20-month turnover. The full quote from the EPRI study is:

> While survey results indicate high levels of satisfaction with the M-Power program and that customers would prefer to continue to remain on the program, the turnover rate of the M-Power program is relatively high. CCTS respondents were on the M-Power program for an average of 20 months (less than two years) as of July 2009, consistent with other CCTS data that has been hovering around the two-year mark since early 2008. [6]

One of the significant populations that benefit from a Prepay program is renters. Renters are typically required to fund property deposits as well as deposits on other utilities. Prepay provides the opportunity to avoid funding any one of many deposits. Renters are also most likely to move from premises to premises more frequently than homeowners. Therefore, a turnover of 20 months does not present as remarkable or cautionary. In fact,

[6] "Paying Upfront: A Review of Salt River Project's MPower Prepaid Program" EPRI October 2010.

since the paper was issued in 2010, SRP enrollment has grown to and maintained annual participation of over 100,000 customers. The stability and size of the SRP program suggest that customers are not trying the program, deciding they don't like it, and then exiting the program. If that were the case, SRP would have turned through their entire customer population and seen a significant decrease in participation as all potential customers became exposed to the program. The Company expects many customers participating in the program will turnover frequently due to the mobility of Tucson's population of students, winter visitors, temporary workers and renters.

Q. Please comment on Ms. Zwick's speculation that the savings from APS' Prepay program is due to the fact that low income customers use less energy.

A. Ms. Zwick's position is inconsistent with national research on Prepay program savings (see Table above and corresponding research). Research indicates Prepay programs are two to four times more effective than other behavioral EE programs, such as Home Energy Reports that the Commission has ordered the Company to implement. Traditional EE Measurement Evaluation and Research ("MER") analysis factor in such effects (i.e., low income, disconnection, etc.). Moreover, whether a customer is low income or not is irrelevant since the analysis performs a pre and post billing MER study on participating customers, which looks at customer's billing history before implementing the Prepay program and then after implementing the program. Another way MER studies account for such items is by selecting a proper control group in which to perform the analysis.

These types of studies are completed by third-party evaluators experienced in performing these analyses for utilities across the nation. In fact, if the multiple evaluations for the behavioral effects of Prepay programs cannot be relied upon, as Ms. Zwick suggests, then this brings into question the evaluation of behavioral programs in general.

Q. Do you have any comment on Ms. Zwick's citation of Distributed Energy Financial Group's (DEFG) report[7] to gauge customer acceptance of Prepay programs?

A. Yes. Ms. Zwick's testimony does not acknowledge the major conclusion of the study titled "Prepay for everyone: Prepay Energy and Higher Income Americans". Ms. Zwick's citation from this report that "a majority of high-income customers were not very interested in prepaid electric service", misleads the reader to believe customers are just not interested in Prepay programs, when in fact the group's press release states:

> The top line finding is that affluent Americans are MORE interested in a voluntary prepay option from the local utility than the general population by 11 percentage points (28% in this survey vs. 17% in our national survey of all consumers conducted late in 2015). This finding strongly refutes the argument that prepay energy is only for low-income customers.

The fact of the matter is that a significant number of customers from all income segments would be "extremely or very interested" if their utility company were to offer a voluntary prepaid option to them.

> 28% of these affluent consumers would be extremely or very interested if their utility company were to offer a voluntary prepaid option. Interest was significantly higher among men (34% v. 21% of women) and those 18-54 (35% v. 11% of those 55 or older). One third of those in households with $75-99k expressed interest compared to 26% of those with somewhat lower incomes and 28% of those with higher incomes.

[7] EcoPinion Consumer Report Mo. 25, "Prepay for everyone: Prepay Energy and Higher Income Americans", Russell Research, June 2016.

The conclusion that I draw from the study is while the majority of customers may not be interested in a Prepay option, there is approximately one quarter of all types of customers that are interested in the program. This level of interest is more than enough to warrant offering the program as an option.

Q. Why is TEP interested in offering a Prepay option to its customers?

A. The Company believes a voluntary Prepay program will be part of standard payment options utilities will offer to provide customers with more choices to meet their individual needs. Other reasons why the Company is interested in offering the program to customers include:

(1) Prepayment is a billing option that a meaningful percentage of customers select when it is made available to them, and has demonstrated correspondingly high customer satisfaction among participants;

(2) Prepayment supports customers who desire assistance with proactively managing their energy budget, similar to how customers use prepaid cellular service;

(3) By participating in the Prepay program, customers do save energy as they receive daily updates on their on their energy consumption and change consumption behavior accordingly;

(4) Prepayment enables the utility to waive the customer deposit requirement enabling customers to apply those funds to meet other needs; and

(5) Prepayment is a billing option many customers are familiar with and chose for other services like cellular phone service.

IV. RESPONSE TO SWEEP.

Q. Do you agree with SWEEP witness Jeff Schlegel's recommendation on page 8 of his Direct Testimony regarding the costs of EE programs being recovered in base rates?

A. No. The Company has been able to meet the Electric EE Standard in a cost-effective manner through the funding mechanisms in place. The funding of DSM programs should continue to be recovered through the DSM surcharge and not through increasing the base rates. Recovering DSM-related expenses through the DSM surcharge provides ratepayers with important transparency of the investment being made in energy efficiency programming. As the regulatory environment for EE continues to evolve with the pending Clean Power Plan, the recovery of expenses should be made through a resource-based decision model and transparent.

Q. Do you agree with SWEEP witness Jeff Schlegel's recommendation at page 15 to address the Prepay program as part of TEP's EE Implementation Plan process?

A. Yes. The EE component of the program must be addressed through the EE plan process as the second part of a two part approval process, the first of which is receiving approval for the Prepay tariff through this rate case.

Q. Do you agree with SWEEP witness Brendon Baatz's recommendations regarding the Prepay program?

A. The Company has agreed to add a Lifeline option as part of the Prepay tariff. The Company does not agree that Prepay customers should have a lower basic service charge and overall rate for the reasons outlined above. Fundamentally, pay-as-you-go is a voluntary billing option, and as such, the Company has agreed to add a Lifeline option, but has no interest in offering it as a bill assistance program. The Company also notes that customers cannot be forced to enroll in Prepay which is a voluntary option.

V. RESPONSE TO RUCO.

Q. Please respond to RUCO witness Jeffrey M. Michlik's testimony regarding credit card processing fees.

A. As noted above, a number of other parties do not support the Company's request to include a portion of credit card fees charged to customers in base rates. The Company therefore withdraws its request in this proceeding. The impact on the revenue requirement is addressed in Mr. Lewis' Rebuttal Testimony.

VI. RESPONSE TO IBEW.

Q. Why has TEP hired seasonal, part-time contractors as customer service representatives?

A. TEP contracted with an agency to hire seasonal, part-time contractors on a temporary basis, to better meet the needs of our customers during high call volume periods. Thus far, this pilot program has proved to be a cost effective solution with promising results. The temporary contractors' schedules vary based on peak call times during the week. This program began on May 23, 2016 and by July 25 2016 all 25 temporary seasonal contractors were trained and taking calls. As of July 15, 2016 the average customer wait time has been reduced by 53% percent when compared to the same period of time last year. The Company believes that the added seasonal part-time contractors have significantly contributed to that improvement.

VII. ADDITIONAL MINOR MODIFICATION TO THE RULES AND REGULATIONS.

Q. Is TEP proposing an additional minor modification to the Rules?

A. Yes. TEP would like to modify language previously submitted as Subsection 11.F.3.e. TEP would like to change "When a Customer signs up for service in error at the wrong premise." to "When a Customer signs up for service in error at the wrong premises or requests disconnection in error at the wrong premises, corrected charges for under billings shall go back to the date of the error."

Q. Does this conclude your Rebuttal Testimony?

A. Yes.