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2016 MAR 25 PM 4 02

Docket #(s): G-04204A-15-0142

Arizona Corporation Commission
DOCKETED
MAR 25 2016
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Exhibit #: S-1-19

Part 5 of 8

For Part 6, See Barcode 0000169261

EXHIBIT
S-1
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

SUSAN BITTER SMITH
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
DOUG LITTLE
Commissioner
TOM FORESE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. 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 UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

DIRECT

TESTIMONY

OF

DONNA H. MULLINAX

ON BEHALF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 6, 2015

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ATTACHMENTS

EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-15-0142

The testimony of Donna Mullinax addresses the following issues, and responds to the testimony of UNS Electric, Inc. (UNSE or "Company") witnesses on these issues:

- The Company's proposed revenue requirement
- Staff's recommended revenue requirement
- Adjusted Rate Base
- Adjusted Test Year revenues, expenses, and net operating income
- Customer Annualization
- Depreciation
- Property Tax Deferral

Staff's findings and recommendations for each of these areas are as follows:

The Company's Proposed Revenue Requirement

UNSE is requesting an increase in base rate revenues of $22.6 million, or approximately 15.4 percent, based on UNSE's adjusted retail electric revenues at current rates of $147.1 million. This increase will be offset by a proposed $14.9 million reduction in fuel costs and revenues due to the Company's acquisition of a 25 percent interest in Gila River Power Plant Unit 3 ("Gila River"), lower power market costs, and adjustments to test year sales. UNSE's proposed base rates also will include $4.3 million in transmission costs currently being recovered through the Transmission Cost Adjustor ("TCA"). The combination of these elements results in a $3.5 million retail revenue increase.

Staff's Recommended Base Rate Revenue Increase

Staff recommends that UNSE be authorized a base rate increase of no more than $18.1 million on adjusted Fair Value Rate Base ("FVRB"). This is an average revenue increase of approximately 12.0 percent to adjusted test year revenues of $154.9 million.

Adjusted Rate Base

The following adjustments to UNSE's proposed rate base should be made.

Adjustment	Description	ACC Jurisdictional OCRB Increase (Decrease)	ACC Jurisdictional RCND Increase (Decrease)
		(Thousands of Dollars)	
E-1	Cash Working Capital	$ 193	$ 193
E-6	D&O Liability Insurance	(17)	(17)
E-10	Gila River Accum Depreciation	(2,000)	(2,000)
	Total Staff Adjustments	$ (1,824)	$ (1,824)
	UNSE Proposed Rate Base	$ 272,013	$ 439,427
	Staff Proposed Rate Base	$ 270,189	$ 437,603

The following table summarizes UNSE's requested and Staff's recommended OCRB, RCND, and FVRB with the differences.

Description	Company	Staff	Difference
	(Thousands of Dollars)		
Original Cost of Rate Base	$ 272,013	$ 270,189	$ (1,824)
RCND Rate Base	$ 439,427	$ 437,603	$ (1,824)
Fair Value Rate Base	$ 355,720	$ 353,896	$ (1,824)

Adjusted Net Operating Income

The following adjustments to UNSE's proposed revenues, expenses, and net operating income should be made.

Adjustment	Description	Pre-Tax Revenue or Expense Adjustment	Net Operating Increase (Decrease)
		(Thousands of Dollars)	
E-2	Bad Debt Expense	$ (132)	$ 82
E-3	Injuries & Damages	(333)	208
E-4	Payroll Expense & Payroll Taxes	(146)	91
E-5	Incentive Compensation	(161)	100
E-6	D&O Liability Insurance	(20)	12
E-7	Interest Synchronization	-	(15)
E-8	Purchased Power & Fuel	-	-
E-9	OATT	(20)	12
	Total Staff Adjustments	**$ (811)**	**$ 491**
	UNSE Adjusted Net Operating Income		$ 8,045
	Staff Adjusted Net Operating Income		$ 8,537

Customer Annualization

Staff is not recommending an adjustment to the Company's revenue requirements for Customer Annualization. However, Staff is recommending that the Company monitor revenues and file quarterly reports with the Commission.

Depreciation

Staff recommends rejecting the Company's proposal to delay full implementation of the new depreciation accrual rates.

Property Tax Deferral

Staff recommends accepting UNSE's proposed property tax deferral. It allows recovery for items that are beyond the control of the Company and balances the interests of consumers and shareholders.

INTRODUCTION

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

A. My name is Donna H. Mullinax. I am employed as Vice President and Chief Financial Officer ("CFO") by Blue Ridge Consulting Services, Inc. ("Blue Ridge"). My business address is 114 Knightsridge Road, Travelers Rest, South Carolina 29690.

Q. Please describe your educational background.

A. I graduated with honors from Clemson University with a Bachelor of Science in Administrative Management and a Master of Science in Management. I am a Certified Public Accountant ("CPA"), Certified Internal Auditor ("CIA"), a Certified Financial Planner ("CFP"), and a Chartered Global Management Account ("CGMA") designation holder. I am a member of the South Carolina Association of Certified Public Accountants, the American Institute of Certified Public Accountants, and the Institute of Internal Auditors.

Q. Please describe your professional experience.

A. I have over 36 years of professional experience. I have held the position of Vice President and CFO for the last 20 years and have served on various Boards of Directors. As Vice President/CFO, I have been responsible for all aspects of finance and administration including accounting, cash management, tax planning and preparation, fixed assets, human resources, and benefits for my current employer and my previous employer, Hawks, Giffels, & Pullin , Inc. ("HGP").

In addition to my corporate responsibilities, I have been a utility industry consultant for the last 22 years. My consulting assignments include management, financial, and compliance audits, due diligence reviews, prudence reviews, and economic viability and financial studies. Other projects include numerous rate cases for natural gas and electric utilities and litigation support for various construction claims. I have worked with public service commissions, attorneys general, and public advocates in Colorado, Connecticut, Delaware, District of Columbia, Hawaii, Illinois, Maryland, Massachusetts, Michigan, Missouri, Nebraska, New York, North Dakota, Ohio, Oregon, and Utah.

From 1991 to 1993, I worked with Cherry, Bekaert & Holland CPAs as a senior accountant and accounting supervisor. My responsibilities included financial and compliance audits, financial reporting, and tax return preparation. From 1988 to 1991, I was a sales representative for Smith, Kline and French Pharmaceutical Company.

I worked with Milliken and Company, a large privately held textile and chemical company, from 1979 through 1988. As head of the Quality Assurance Department, I was actively involved in numerous operations' audits supporting Milliken's Quality Program. As the Technical Cause Analyst, I analyzed complex quality and production problems to develop corrective actions through advanced statistical and problem-solving techniques. I conducted training seminars for production associates and management on statistical quality control techniques. I held various production management positions with the responsibility of controlling cost, schedule, production, and quality within areas under my control.

Q. Have you included a more detailed description of your qualifications?

A. Yes. A description of my qualifications is included as Attachment DHM-1.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Utilities Division Staff ("Staff") of the Arizona Corporation Commission ("ACC" or "Commission").

Q. Have you previously testified before the Arizona Corporation Commission?

A. No. I have not testified before this Commission.

Q. In what other jurisdictions have you previously appeared as a witness or filed testimony?

A. I have testified in Colorado, Delaware, Maryland, Michigan, and Nebraska. I have also supported other experts' testimonies in numerous other jurisdictions and have served as an advisor to the Commission and Staff for the District of Columbia Public Service Commission for a number of gas and electric proceedings.

Q. What is the purpose of the testimony you are presenting?

A. The purpose of my testimony is to address the rate base, adjusted net operating income, and revenue requirements proposed by UNS Electric, Inc. ("UNSE" or "Company").

Q. Are you presenting any exhibits in connection with your direct testimony in this proceeding?

A. Yes. Attachment DHM-2 includes Staff's accounting schedules. Attachments DHM-3 through DHM-20 are copies of selected documents that are referenced in my testimony.

Q. How are Staff's accounting schedules organized?

A. Staff's accounting schedules included in Attachment DHM-2 are organized into summary schedules and adjustment schedules. The schedules consist of Schedules A, A.1, B, C, D, D.1, E, and E-1 through E-10.

Q. What is shown on Schedule A?

A. Schedule A presents the overall summary reflecting all of the Staff adjustments and the change in the Company's revenue requirement needed for the Company to have the opportunity to earn Staff's recommended rate of return on Staff's proposed Original Cost and Fair Value rate bases. The rate base and operating income amounts are taken from Schedules B and C, respectively. The overall rate of return, as presented by Staff witness Elijah Abinah, is provided on Schedule D for convenience.

Q. What is shown on Schedule A-1?

A. Schedule A-1 presents Staff's gross revenue conversion factor ("GRCF"), which is used to convert the net operating income deficiency into a revenue deficiency amount. The conversion factor grosses up the revenue needed to be collected from customers to recognize that more than one dollar in gross revenue is needed for each dollar of net operating income to take into account the imposition of taxes on those earnings.

The GRCF also recognizes that some revenues will not be collected and must be recognized as bad debt. Schedule A-1 includes a Staff adjustment to remove the unusual and nonrecurring reserve for the bankruptcy of a large mining company from the derivation of the Uncollectible Revenues used in the GRCF as discussed in Staff's adjustment for Bad Debt (Schedule E-2). Staff's adjustment reduces the GRCF from 1.6084 to 1.6070.

Q. What is shown on Schedule B?

A. Schedule B presents UNSE's proposed test year Original Cost Rate Base ("OCRB") and Reconstruction Cost New Less Depreciation ("RCND") rate base. Staff's recommended rate base adjustments are also summarized to derive the "As Adjusted by Staff" OCRB and RCND balances. Staff's recommended adjustments are addressed separately in this testimony and are included within the E Schedules. The OCRB and RCND are used to determine the Fair Value Rate Base ("FVRB"). Schedule B shows the derivation of the FVRB.

Q. How was the Fair Value Rate Base determined?

A. As shown on Schedule B, the FVRB was determined by averaging the OCRB and RCND, giving equal weight to both consistent with prior Commission practice.

Q. How did the Company develop the Reconstruction Cost New Less Depreciation?

A. The RCND rate base is derived from the Reconstruction Cost New ("RCN") and adjusted for book depreciation. The RCN is the estimated cost of constructing the Company's property at today's cost levels. A trending study establishes an index number that represents a ratio between the cost of an item in the year it was put in-service (or vintage) and its cost at a base period. The indices are applied to the Company's original cost to estimate the reconstruction or reproduction cost at current levels. Once the RCN is established, it is multiplied by a net book value percentage, which is the original cost less depreciation divided by original cost, to develop the RCND.[1]

Q. What is shown on Schedule C?

A. The first column in Schedule C is UNSE's adjusted test year net operating income. Staff's recommended adjustments to UNSE's adjusted test year revenues and expenses are summarized, with each adjustment addressed separately, in this testimony, and included within the E Schedules. The last column provides the "As Adjusted by Staff" test year net operating income.

Q. What is shown on Schedules D and D-1?

A. Schedule D summarizes the capital structure and cost of capital proposed by the Company and the capital structure and cost of capital recommended by Staff witness Elijah Abinah. Schedule D-1 isolates the impact on revenue requirements for the difference in UNSE's proposed capital structure and cost of capital and that recommended by Staff.

[1] Direct Testimony of David Lewis, page 5, line 16 through page 6, line 23.

Q. What is shown on Schedule E and Schedules E-1 through E-10?

A. Schedule E summarizes Staff's adjustments to rate base and operating income (revenues less expenses). Schedules E-1 through E-10 provide further support and calculations for the adjustments Staff is recommending.

REVENUE REQUIREMENT

Revenue Requirement Proposed By UNS Electric, Inc.

Q. What revenue increase has been requested by UNSE?

A. UNSE is requesting an increase in base rate revenues of $22.6 million, or approximately 15.4 percent, based on UNSE's adjusted retail electric revenues at current rates of $147.1 million. This increase will be offset by a proposed $14.9 million reduction in fuel costs and revenues due to the Company's acquisition of a 25 percent interest in Gila River Power Plant Unit 3 ("Gila River"), lower power market costs, and adjustments to test year sales. UNSE's proposed base rates also will include $4.3 million in transmission costs currently being recovered through the Transmission Cost Adjustor ("TCA"). The combination of these elements results in a $3.5 million retail revenue increase.

In addition, UNSE is proposing a one-year credit to the purchased power and fuel adjustment clause ("PPFAC") to reflect the deferred savings accrued as a result of the Accounting Order related to the acquisition of Gila River (estimated at $9.3 million).[2] As a result of these factors, UNSE's request would decrease revenues by approximately $5.8 million, or 3.6 percent, in the first year after new rates take effect.[3] Once that temporary credit expires,

[2] Decision No. 74911, dated January 22, 2015.
[3] UNSE Application, dated May 5, 2015, page 1-2.

one year after new rates take effect, the Company's proposal would increase retail revenues by approximately $3.5 million, or 2.1 percent.[4]

The following table was provided by the Company and reflects the Company's proposed Requested Retail Rate Impact.

Table 1: UNSE Proposed Retail Rate Impact[5]
(Thousands of Dollars)

Summary of Requested Retail Rate Impact					
				Yr. 1	Yr. 2
	Requested Non-fuel Increase	$	22,622		
Less:	TCA Added To Base Rates		(4,292)		
	Reduction in Base Fuel Rates		(14,870)		
	Gila River Deferred Savings (est.)			$ (9,300)	$ -
	Net (Reduction)/Additional Retail Revenue			$ (5,840)	$ 3,460
	Test Year Adjusted Retail Revenue (Excluding TCA Revenue)	$	147,107		
Plus:	Revenue Paid Through TCA Tracker		4,292		
	Base Fuel Changes Due to Gila & Market Rate Changes		12,345		
	Test Year Adjusted Retail Revenue			$ 163,744	$ 163,744
	Percentage Impact			-3.57%	2.11%

Revenue Requirement Recommended By Staff

Q. What revenue increase does Staff recommend?

A. Staff recommends a base rate increase of no more than $18.1 million on FVRB.

[4] Direct Testimony of David Hutchens, page 3, line 22 through page 4, line 1.
[5] UNSE Application, dated May 5, 2015, page 6.

Test Year

Q. What test year is being used in this case?

A. UNSE has based its revenue requirement on a historical test year ended December 31, 2014. Staff's calculations use the same historical test year.

ADJUSTMENTS TO RATE BASE

Q. Have you prepared a schedule that summarizes Staff's proposed adjustments to rate base?

A. Yes. The adjusted rate base is shown on Schedule B and Staff's adjustments to UNSE's proposed rate base are provided on Schedule E. A comparison of the Company's proposed rate base and Staff's recommended rate base on Original Cost and Fair Value is shown in the following table.

Table 2: Comparison of UNSE's Proposed and Staff's Recommended Rate Base
(Thousands of Dollars)

Description	Company	Staff	Difference
Original Cost of Rate Base	$ 272,013	$ 270,189	$ (1,824)
RCND Rate Base	$ 439,427	$ 437,603	$ (1,824)
Fair Value Rate Base	$ 355,720	$ 353,896	$ (1,824)

Q. Are there any of the Company's rate base adjustments to which Staff is not proposing an adjustment?

A. Yes. Staff is not recommending a modification to the following UNSE rate base adjustments:

- Acquisition Discount Adjustment
- Accumulated Deferred Investment Tax Credit ("ITC")
- Accumulated Deferred Income Tax ("ADIT")

- Fortis Rate Base Adjustment
- Asset Retirement Obligation ("ARO")

Q. Is the Company requesting recovery for any post-test year plant?

A. No. UNSE is not requesting a post-test-year adjustment to include plant that would be used and useful prior to a new rate order.[6]

Q. Are all additions to plant used and useful?

A. Staff's engineering assessment found that the plant inspected was used and useful. Staff witness Howard Solganick presents the engineering assessment.

Q. What adjustments is Staff recommending to UNSE's proposed rate base?

A. Staff recommends adjustments to Cash Working Capital, Prepaid Directors & Officers ("D&O") Liability Insurance, and Gila River Deferred Cost Accumulated Depreciation.

Cash Working Capital

Q. Please explain your adjustment E-1 – Cash Working Capital.

A. The Company's proposed rate base includes Cash Working Capital, which was developed through the preparation of a lead-lag study. Staff's adjustment updates the revenue and expense components of the Company's lead-lag study to reflect Staff's adjustments that are discussed within this testimony. Staff's adjustment to Cash Working Capital increases jurisdictional rate base by $192,930.

[6] Direct Testimony of David Lewis, page 15, lines 18-22.

Q. Is the Company's lead/lag study reasonable and in compliance with past Commission preferences?

A. Yes. The Company's lead/lag study is well documented. Revenue lags and payment leads and lags are not out of line.

Prepaid Directors and Officers Liability Insurance

Q. Please explain your adjustment to rate base identified as adjustment E-6 – Prepaid Directors and Officers Liability Insurance.

A. This adjustment removes one-half of the prepaid D&O Liability Insurance the Company included within rate base. The adjustment is made to be consistent with the adjustment to D&O Liability Insurance expense discussed later. The adjustment reduces jurisdictional rate base by $16,778.

Gila River Deferred Cost accumulated Depreciation

Q. Please explain Staff adjustment E-10 – Gila River Deferred Cost Accumulated Depreciation.

A. Staff witness Barbara Keene presents Staff's Gila River Deferred Cost Accumulated Depreciation Adjustment. The adjustment reduces rate base by $2,000,000.

ADJUSTMENTS TO OPERATING INCOME

Q. Have you prepared a schedule that summarizes Staff's proposed adjustments to Operating Income?

A. Yes. The adjusted operating income is shown on Schedule C, and the adjustments to UNSE's test year revenue and expenses are shown on Schedule E. A comparison of the Company's proposed operating income and Staff's recommended operating income is shown in the following table:

Table 3: Comparison of UNSE's Proposed and Staff's Recommended Operating Income (Thousands of Dollars)

Description	Company	Staff	Difference
Revenues	$ 148,935	$ 156,716	$ 7,782
Expenses	$ 140,889	$ 148,180	$ 7,290
Operating Income	$ 8,045	$ 8,537	$ 491

Q. Are there any of the Company's operating income adjustments to which Staff is not proposing an adjustment?

A. Yes. Staff is not recommending a modification to the following UNSE Operating Income adjustments:

- LFCR
- Non-Retail Revenue, Fuel & Purchased Power
- Weather Normalization
- REST & DSM
- Pension and Benefits
- Retiree Medical

- Rate Case Expenses
- Depreciation and Amortization Expense
- Property Tax
- Membership Dues
- Gila River Deferred Costs
- Fortis Acquisition Costs
- Other Revenue
- Gila River O&M And Outages

Q. What adjustments is Staff recommending to UNSE's proposed Operating Income?

A. Staff is recommending adjustments to Customer Annualization, Bad Debt Expense, Injuries and Damages, Payroll Expenses, Payroll Taxes, Incentive Compensation, D&O Liability Insurance, Interest Synchronization, Purchased Power & Fuel Adjustment (PPFAC), and OATT.

Customer Annualization

Q. Is Staff recommending an adjustment to the current base rates for customer Annualization?

A. No. Staff is not recommending an adjustment to the Company's revenue requirements for Customer Annualization. However, Staff is recommending that the Company monitor revenues and file quarterly reports with the Commission.

Q. Why is Staff recommending monthly monitoring of revenues?

A. The Company's Customer Annualization Adjustment reflected a change in the number of customers in the various classes. The Residential and Small General Service experienced increases, but the larger classes experienced reductions that will have a significant impact on sales levels due to the loss of two large customers in the current Large Power Service Classes.[7] The total sales loss, based on the test year and adjusted for unbilled sales, is 64 GWh. The corresponding revenue amount (excluding REST, DSM, taxes and assessments) is $6.2 million.[8] Should the facilities of these two customers reopen, revenues will increase substantially.

Q. How should the Commission monitor UNSE's revenues?

A. Staff recommends that the Commission require UNSE to file quarterly reports that include monthly revenue data from the previous period. This information should be filed, as a compliance item in this docket, no later than the first of each month beginning January 1, 2017, and continue until UNSE files its next rate case application.

Bad Debt Expense

Q. Please explain Staff adjustment E-2 – Bad Debt Expense.

A. Consistent with the last rate case, the Company normalized bad debt expense using a three-year average retail expense ratio. This ratio is based upon retail revenues and bad debt expense.[9] Staff recommends that the Company average the dollar amounts to derive the Average Retail Expense Ratio instead of averaging the averages.

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[7] Direct Testimony of Craig Jones, page 68, lines 9-16.
[8] UNSE response to STF 20.11 (Attachment DHM-20).
[9] UNSE response to UDR 1.001 Income-Bad Debt Expense (Attachment DHM-4).

Staff's adjustment removes a $450,000 reserve from the 2014 Bad Debt Expense related to the bankruptcy of a large mining company[10] as shown in the following table.

Table 4: Bad Debt Expense Removing Reserve for Bankruptcy

Year	Bad Debt	Bankruptcy	Adjusted Bad Debt
2012	$ 518,681		$ 518,681
2013	$ 310,216		$ 310,216
2014	$ 863,828	$ (450,000)	$ 413,828

The recording of such a large Bad Debt reserve is an atypical, unusual, and nonrecurring event that should be removed from a normalizing adjustment. Staff's adjustment increases Operating Income by $82,126.

Q. Does this adjustment also impact the gross revenue conversion factor?

A. Yes. Removing the unusual and nonrecurring reserve for the bankruptcy of a large mining company from the derivation of the Average Retail Expense Ratio also impacts the percent of Uncollectible Revenues used in the Gross Revenue Conversion Factor shown on Schedule A-1. Staff's adjustment reduced the ratio from 0.3438 percent to 0.2543 percent.

Injuries and Damages

Q. Please explain Staff adjustment E-3 – Injuries and Damages.

A. The Company normalized the test year injuries and damages using a three-year average as shown in the following table.

[10] UNSE response to UDR 1.053 (Attachment DHM-5).

Table 5: UNSE Normalized Injuries & Damages[11]

Year	Workers Comp	Injuries & Damages	Total
2012	$ 22,670	$ 10,000	$ 32,670
2013	$ 62,687	$ 1,071,000	$ 1,133,687
2014	$ 27,797	$ -	$ 27,797
Average	$ 37,718	$ 360,333	$ 398,051

Staff's adjustment removes a $1,000,000 insurance deductible paid out for an accident in 2013 that was included within the three-year average resulting in the following three-year average.

Table 6: Staff's Adjustment to Injuries & Damages

Year	Workers Comp	Injuries & Damages	Total
2012	$ 22,670	$ 10,000	$ 32,670
2013	$ 62,687	$ 71,000	$ 133,687
2014	$ 27,797	$ -	$ 27,797
Average	$ 37,718	$ 27,000	$ 64,718

As stated by the Company, "Normalization adjustments reflect that the recorded Test-Year operating revenues and expenses may not be representative of a normal level for ratemaking purposes. Certain events may have affected recorded transactions in an atypical manner."[12] Paying out a $1,000,000 insurance deductible is atypical, unusual, and nonrecurring and should not be included in future rates. Staff's adjustment results in an increase to Operating Income of $207,954.

[11] UNSE response to UDR 1.001 Income-Injuries and Damages (Attachment DHM-6).
[12] Direct Testimony of David Lewis, page 12, lines 10-13.

Payroll Expense and Payroll Taxes

Q. Please explain Staff adjustment E-4 – Payroll Expense

A. Incentive Compensation dollars were included in both O&M Payroll and the Company's Incentive Compensation adjustment. Staff's adjustment for Payroll Expense removes the incentive compensation amounts from payroll and makes the adjustment within the Incentive Compensation adjustment.

Q. Please elaborate.

A. The Company's Payroll adjustment is based on a two-year average of Total O&M Payroll with an incremental 2 percent wage increase for 2015 and 2016. The detailed work papers developing the Total O&M Payroll for 2013 and 2014 were found to include amounts for incentive compensation totaling $145,417 and $134,246, respectively. The amounts represent 50 percent of the non-executive short-term incentive compensation consistent with past Commission precedent.[13] Removing incentive compensation from the Payroll Adjustment increases Operating Income by $91,068 (including the payroll tax impact).

Incentive Compensation Expense

Q. Please explain Staff adjustment E-5 – Incentive Compensation.

A. The Company is seeking 100 percent recovery of short-term incentive compensation for unclassified employees, officers, and senior management based on a three-year average (2012-2014). The Company's adjustment also includes an expected incremental increase of 2 percent

[13] UNSE response to STF 6.12 (Attachment DHM-8).

for 2015, 2016, and 2017. The Company's adjustments bring the total incentive compensation to $326,753 (including payroll taxes).[14]

Beyond the potential for double counting of Incentive Compensation in both this adjustment and the Payroll Expense addressed in Staff's Payroll Expense Adjustment, Staff has a number of other concerns about the Company's incentive compensation adjustments.

First, incentive compensation is normalized based on the three-year average. The normalizing of incentive compensation should be consistent with the approach used by the Company for Payroll Expense. The Company normalizes Payroll Expense using a two-year average; incentive compensation should also be normalized in the same manner.

Second, amounts that are not known and measureable should not be included in the Incentive Compensation adjustment. The Company stated that the 2017 merit increase is not yet known and measureable.[15]

Third, the Company's Incentive Compensation includes 100 percent of the costs which is inconsistent with prior Commission practice that has required Incentive Compensation expense to be shared 50/50 with shareholders.

[14] UNSE response to UDR 1.001 Income-Incentive Compensation (Attachment DHM-10).
[15] UNSE response to STF 6.15 (Attachment DHM-11).

Q. What does Staff recommend?

A. There are several parts to Staff's adjustment. First, Incentive Compensation should be normalized similar to Payroll Expense. Thus, Staff's adjustment uses a two-year average instead of the three-year average used by the Company.

Second, Staff recommends that the 2017 merit increase be excluded as not known and measureable. Payroll Expense included the known and measureable increases for 2015 and 2016, and Incentive Compensation should be consistent with the Company's treatment of Payroll Expense.

Finally, Incentive Compensation should be shared with shareholders. Thus, Staff's adjustment reduces Incentive Compensation by half, to 50 percent.

Q. Please explain why shareholders should share in the incentive compensation program.

A. Incentive compensation programs can provide benefits to both shareholders and ratepayers. The removal of 50 percent of the Incentive Compensation expense provides an equal sharing of those costs and provides an appropriate balance between the benefits attained by both shareholders and ratepayers.

Q. Please describe UNSE's Incentive Compensation Program.

A. All UNSE non-union employees participate in UNSE's short-term incentive program, or Performance Enhancement Plan ("PEP"), which is tied to annual compensation. The financial and other metrics for the Company's 2014 short-term incentive compensation program were:

- Financial – 50 percent
    - Net Income – 40 percent
    - O&M Cost Containment – 10 percent
- Excellent Operations and Safe Work Environment – 50 percent

The Company stated that "The Compensation Committee selected the goals and individual weights for the 2014 PEP to ensure an appropriate focus on profitable growth and expense control, as well as operational and customer service excellence, and process improvements. This balanced scorecard approach encourages all employees to work toward common goals that are in the interests of UNS Energy's various stakeholders."[16]

The scores from each goal are totaled and then multiplied by the target bonus of each employee to determine the total available dollars to be paid out. Target bonus percentages, as a percent of base salary, range from 3 percent to 14 percent for unclassified employees and from 20 percent to 25 percent for senior management level employees.[17]

Q. Is the Company's adjustment for Short-Term Incentive Compensation consistent with prior rate case Orders?

A. No. Although the revenue requirement in UNSE's most recent rate case was settled and approved in Decision No. 74235 (September 30, 2013), Staff's direct testimony prior to settlement recommended continuing the 50 percent allocation for UNSE's incentive compensation expense to shareholders as had been ordered by the Commission in Decision

[16] UNSE response to UDR 1.034 (Attachment DHM-12).
[17] UNSE response to UDR 1.034 (Attachment DHM-12).

No. 71914 (September 30, 2010). Decision No. 71914 set forth the basis for the 50 percent allocation at pages 27-29:[18]

> "We believe that the Staff and RUCO recommendations, to require a 50/50 sharing of incentive compensation costs, provide a reasonable balancing of the interests between ratepayers and shareholders. The equal sharing of such costs recognizes that the program is comprised of elements that relate to the parent company's financial performance and cost containment goals, matters that primarily benefit shareholders, while at the same time recognizing that a portion of the program's incentive compensation is based on meeting customer service goals. This offers the opportunity for the Company's customers to benefit from improved performance in that area." [19]

Q. What is the reason the Company gives for its request to recover 100 percent of its Short-Term Incentive Compensation despite prior Commission orders?

A. The Company stated that the Commission allowed recovery of 100 percent of Arizona Public Service Company ("APS") in Decision No. 69663 (dated June 28, 2007), page 37.[20]

Q. Has Staff previously recommended and the Commission adopted the sharing of short-term incentive compensation between ratepayers and shareholders?

A. Yes. For example, in reaching its conclusions regarding SWG Management Incentive Plan ("MIP") the Commission stated in part on page 18 of Decision No. 68487 that:

> We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Although achievement of the performance goals in the MIP, and the benefits attendant thereto, cannot be precisely quantified there is little doubt that both shareholders and ratepayers derive some benefit from incentive goals. Therefore, the costs of the program should be borne by both groups and we find Staff's equal sharing recommendation to be a reasonable resolution.

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[18] UNSE response to UDR 1.062 (Attachment DHM-12).
[19] Docket No. E-04204A-09-0206, Decision No. 71914, page 28.
[20] Direct Testimony of David Lewis, page 29, line 19 through page 30, line 6.

And, in Decision No. 70011 at page 27, the Commission stated:

> We believe that Staff's recommendation provides a reasonable balance of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program.

The Commission again accepted Staff's recommendation in Decision No. 70360, page 21:

> Consistent with our finding in the UNS Electric rate case (Decision No. 70011, at 26-27), we believe that Staff's recommendation provides a reasonable balancing of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program ... Given that the arguments raised in the UNS Electric case are virtually identical to those presented in this case, we see no reason to deviate from that recent decision.

Q. Is the Company's argument in this proceeding a different argument from that presented in the last base rate case?

A. No. The Company used the same reasoning in the last base rate case.

Q. Has the Company's Short-Term Incentive Compensation materially changed since the last UNSE rate case that would warrant a different decision?

A. No. The Company did not present any material changes to its short-term incentive plan that would warrant reconsidering past Commission practice.

Q. Please summarize Staff's recommended adjustment regarding UNSE's Short-Term Incentive Compensation Program.

A. Incentive Compensation is normalized using two years rather than three years. In addition, the 2017 merit increase was excluded as not known and measureable. Further, Incentive Compensation was reduced by half for the portion to be shared with shareholders. Therefore, Staff's adjustment increases Operating Income by $100,178.

Directors and Officers Liability Insurance

Q. Please explain Staff adjustment E-6 – D&O Liability Insurance.

A. This adjustment removes one-half of the D&O Liability Insurance expense. The removal of one-half of this expense reflects a sharing of this insurance between shareholders and ratepayers. Staff's adjustment increases Operating Income by $12,495.

Q. Why should the cost of D&O Liability Insurance Expense be shared between shareholders and ratepayers?

A. D&O Liability Insurance protects the officers and directors from the costs of a lawsuit. Shareholders benefit from payouts under the policy that would reduce the cost not recoverable from ratepayers. On the other hand, ratepayers benefit because having the insurance improves the ability of the Company to attract and retain qualified directors and officers and enables the directors and officers to make decisions without fear of personal liability. As a result, it is reasonable for shareholders to bear some of the cost of D&O Liability Insurance.

Q. Was this adjustment made in the last rate case?

A. Yes. Although the revenue requirement in UNSE's most recent rate case was settled and approved in Decision No. 74235 (September 30, 2013), Staff's direct testimony prior to settlement recommended sharing the D&O Liability Insurance between consumers and shareholders by reducing it by 50 percent.

Q. Did the Company make an adjustment to D&O Liability Insurance?

A. Yes. The total D&O Liability Insurance for 2014 was $145,954, which was a substantial increase from prior years (2012 - $58,996, 2013 - $69,423)[21]. The Company explained that included within the 2014 amount of $145,954 was $105,899 related to the additional run-off insurance expense that was recognized due to the merger with Fortis. These costs ($109,095 including taxes) were excluded in the Fortis Acquisition Cost adjustment, leaving a net amount of D&O Liability Insurance of $40,055 ($145,954 less $105,899) in the test year.[22] However, there is no indication that the Company made the adjustment to share the expense between shareholders and ratepayers as had been done in the last rate case.

Q. Is there a related adjustment to rate base?

A. Yes, an adjustment was made to remove one half of the prepaid component of the D&O Liability Insurance included in rate base.

Interest Synchronization

Q. Please explain Staff adjustment E-7 – Interest Synchronization.

A. The interest synchronization adjustment synchronizes the rate base and cost of capital with the tax calculation. The adjustment applies the weighted cost of debt to the calculation of test year income tax expense. The result is an adjustment to the amount of synchronized interest included in the tax calculation. The adjustment reduces the Operating Income by $15,085.

[21] UNSE Supplemental Response to UDR 1.059 (Attachment DHM-14)
[22] UNSE response to STF 16.05 (Attachment DHM-15).

Purchased Power and Fuel Adjustment

Q. Please explain Staff adjustment E-8 – PPFAC.

A. Staff witness Barbara Keene presents Staff's Purchased Power and Fuel Adjustment. The adjustment has no net impact on Operating Income.

OATT

Q. Please explain Staff adjustment E-9 – OATT.

A. Staff witness Eric Van Epps presents Staff's OATT adjustment. The adjustment increases Operating Income by $12,431.

Service Fees

Q. Does Staff recommend any other adjustments to Operating Income?

A. Possibly. The Company has revenue associated with Service Fees that will need to be trued up based on the final rate design.

Miscellaneous Expenses

Q. Did Staff review any other expense items that were not adjusted by the Company during its analysis?

A. Yes. Staff reviewed various expenses including those within the Company's miscellaneous expenses accounts. Staff found a number of items that required additional discovery to fully understand whether they were appropriately included within the Company's revenue request.

Q. Does Staff recommend any adjustments associated with this review of miscellaneous expenses?

A. No.

FORTIS ACQUISITION COSTS

Q. Did the Company address the rate case related conditions in the Fortis/UNS Energy merger settlement agreement?

A. Yes. There were 66 settlement conditions within the Settlement Agreement that the Commission approved in Docket Nos. E-04230A-14-0011 and E-01933A-14-0011 in Decision No. 74689 (August 12, 2014). The Company's direct testimony identified and reported on its compliance to 14 settlement conditions.[23] The Company explained that it reported on the settlement conditions that were rate case related in this proceeding. The Company will report on its compliance with the other settlement conditions in an Annual Reporting anticipated to be filed on April 1, 2016, in compliance with Condition No. 43 of the Settlement Agreement.[24]

Q. Is the Company in compliance with the settlement conditions that it reported on in this proceeding?

A. Yes. The rate case related settlement conditions reported on by the Company require the removal of any recovery of costs associated with the merger. The Company is in compliance with the following conditions:

[23] Direct Testimony of Kentton Grant, page 13, line 11 through page 16, line 18, and UNSE response to STF 16.14 (Attachment DHM-17).
[24] UNSE response to STF 19.1 (Attachment DHM-18).

- Condition 5: The Company is not seeking recovery of or on any acquisition premium or goodwill amount in this rate proceeding.
- Condition 6: The revenue requirement does not include any allocated Fortis costs.
- Condition 7: The revenue requirement does not include costs for shareholder litigation related to the merger to ratepayers.
- Condition 8: The revenue requirement does not include recovery of or on the transaction and transition costs associated with the merger.
- Condition 8 (additional element): The revenue requirement does not include recovery of any Change of Control and Retention payments related to the merger.
- Condition 9: The revenue requirement does not include impacts of any fluctuations in foreign exchange rates and any incremental taxes arising from its international ownership structure.
- Condition 10: Fortis has not made an acquisition since the approval of the Fortis/UNS Energy merger that has had any material adverse impact on UNSE.
- Condition 11: The revenue requirement in this case does not include any increase in the total compensation of the Senior Management Personnel. The 11 executive officers of UNS Energy as of August 12, 2014, have been reduced to 10 due to the retirement of Paul Bonavia. The portion of the compensation for those Senior Management Personnel that is allocable to UNSE has been reduced.
- Condition 12: Fortis has not completed any merger or acquisition within the United States since the approval of the Fortis/UNS Energy merger.

- Condition 13: Goodwill and transaction costs of the merger have been excluded from the rate base, expenses, and capitalization in the determination of rates and earned returns of UNSE.
- Condition 15: The revenue requirement does not reflect any recovery or recognition in the determination of rate base of any legal or financial advisory fees or other external costs associated with the merger.
- Condition 17: The capital structure in this docket is separate from that of Fortis. The Company has used UNS Electric's actual capital structure in this rate case.

Q. Are you addressing Staff's position regarding the Buy-Through Tariff that was part of the settlement agreement in the acquisition of UNS Energy by Fortis?

A. No. Staff witness Howard Solganick will address Staff's position regarding the Buy-Through Tariff in his rate design testimony.

DEPRECIATION STUDY

Q. Is UNSE proposing new deprecation rates?

A. Yes. The Company is proposing new depreciation rates based on an updated depreciation study performed by Foster Associates. The new rates update the depreciation rates approved by the Commission in Decision No. 71914 (September 30, 2010).[25] The new depreciation rates are lower for many asset accounts and result in lowering the composite depreciation rate on

[25] UNSE Application, dated May 5, 2015, pages 8-9.

distribution plant from 3.97 percent to 1.39 percent.[26] The Company's annual depreciation expense would be reduced by about $7.8 million.

Q. Has the Company expressed any concerns regarding the reduction in depreciation expense?

A. Yes. Since depreciation is a non-cash expense, the change in revenues attributable to a change in depreciation impacts the Company's operating cash flow.[27] Operating cash flow is a key factor considered by credit rating agencies. The Company has expressed concern that the reduced cash flow from the depreciation expense change and the additional $40 million of debt in late 2014 to fund a portion of the Gila River purchase and other capital expenditures (representing a 30 percent increase in total debt) may influence its credit rating. UNSE states that if the Company's rate application is approved largely as filed, UNSE's operating cash flow is expected to improve over time, even with the proposed reduction in depreciation rates. However, if the Company's proposed revenue requirement is changed in a manner that materially reduces expected operating cash, the Company requests that the change in depreciation rates for the Company's distribution plant be implemented over two rate cases instead of one, with approximately one-half of the change being implemented in this rate case and the remaining half implemented in UNSE's next rate case.[28]

[26] Direct Testimony of Kentton Grant, page 12, lines 1-4.
[27] Direct Testimony of Kentton C. Grant, page 11, lines 17-25.
[28] Direct Testimony of Kentton Grant, page 12, line 22 through page 13, line 4.

Q. What is Staff's recommendation regarding the Company's proposal to split the implementation of the new depreciation accrual rates?

A. Staff recommends rejecting the Company's proposal to delay full implementation of the new depreciation accrual rates. The Company has been over accruing depreciation on the distribution assets and the new rates correct this situation.

PROPERTY TAX DEFERRAL

Q. What is the Company requesting regarding property tax deferral?

A. UNSE is requesting authority to defer 100 percent of the Arizona property taxes above or below the test year level caused by changes in the composite property tax rate and changes in the Gila River valuation methodology. In addition, UNSE is requesting authority to defer all costs associated with appealing Gila River property values. Beginning on the effective date of the Company's next rate case, the deferral balance, whether positive or negative, would be amortized over three years.[29]

Q. Why is the Company asking for a property tax deferral?

A. Since property taxes are a function of property values, taxing authorities must raise tax rates to maintain revenues. Total property values have seen steep declines in recent years in Mohave and Santa Cruz counties. As a result of these property declines, property tax rates have risen. For most taxpayers, lower values and higher tax rates would not necessarily change the taxpayer's tax payment. However, for UNSE, the assessed value is based primarily on the book value of its fixed assets, a value that is typically rising, as UNSE's annual capital expenditures

[29] UNSE Application, dated May 5, 2015, page 10.

tend to exceed the total annual depreciation expense. As a result, when a taxing authority raises rates, UNSE's tax payment rises. This trend is expected to continue and test year level property taxes will fall short of actual payments.[30]

Q. Has the Commission granted other property tax deferrals?

A. Yes. The Commission approved the rate case settlement agreement that provided a property tax deferral for APS in Decision No. 73183 (May 24, 2012). The Settlement defined the property tax deferral as follows:

> XII. COST DEFERRAL RELATED TO CHANGES IN ARIZONA PROPERTY TAX RATE
>
> 12.1 APS shall be allowed to defer for future recovery, in accordance with the provisions of Accounting Standards Codification ("ASC") 980 (formerly SFAS No. 71), the following portions of Arizona property tax expense above or below the test year level of $141.5 million caused by changes to the applicable Arizona composite property tax rate (not changes in the assessed value of property).
>
> (a) When the property tax rate increases:
>
> - For 2012: 25% (prorated with an assumed July 1 rate effective date);
> - For 2013: 40%; and
> - For 2014 and all subsequent years: 75%
>
> (b) When the property tax rate decreases: 100% in all years
>
> 12.2 Beginning with the effective date of the Commission decision resulting from APS's next general rate case, any final property tax rate deferral that has a positive balance will be recovered from customers over 10 years and any deferral that has a negative balance will be refunded to customers over 3 years.
>
> 12.3 The Signatories reserve the right to review APS's property tax deferrals for reasonableness and prudence such that the deferrals can

[30] Direct Testimony of Jason Rademacher, page 15, line 20 through page 17, line 3.

be recognized in accordance with the provisions of ASC-980 (formerly SFAS No. 71).[31]

Q. How is UNSE's proposed property tax deferral different from that which the Commission approved for APS?

A. For its property tax deferral, UNSE proposes recovery of 100 percent of any property tax increase or decrease, whereas the APS property tax deferral has limitations based on the percentage increase in the property tax rate. UNSE's proposal would recover both positive and negative balance over the same three-year period, whereas the APS property tax deferral required the Company to recover positive balances over ten years and negative balances to be refunded to customers over three years. In addition, UNSE is requesting a property tax deferral related to changes in Gila River valuation methodology and the cost of appealing the Gila River value. The Company explained, "While the Settlement Agreement [referring to APS] as a whole may have balanced the interest of consumers and shareholders, the property tax deferral, as a stand-alone provision is not balanced. UNS Electric proposes that the Property Tax Deferral stand alone as a balanced provision."[32]

Q. Please explain why UNSE is requesting inclusion of changes to the Gila River valuation methodology and the cost of appealing its value in its property tax deferral.

A. The Company and the Arizona Department of Revenue ("ADOR") have taken different positions on the interpretation of Arizona property tax law related to the valuation of generation facilities and how the Gila River generation assets should be valued. Since UNSE is not the original owner of Gila River, ADOR has taken the position that Gila River's valuation

[31] Docket No. E-01345A-11-0224, Decision No. 73183, Exhibit A, page 16 of 22.
[32] UNSE response to STF 6.22 (Attachment DHM-19).

should be based upon the $50 million full cash value. UNSE has interpreted Arizona property tax law to mean that the valuation should be based on the seller's cost as reported on the property tax returns immediately prior to acquisition (or the net book value, which is about $29 million). The difference of $21 million is substantial. UNSE plans to appeal the ADOR full cash value decision but must make tax payments based on the higher $50 million valuation until the appeal process is complete which will take several years. Thus, UNSE is requesting authority to defer property tax savings derived from appealing the Gila River full cash value along with all costs associated with the appeal process.[33]

Q. How is the Company recommending that the property deferral be calculated?

A. The Company has proposed the following calculation be performed for each tax year until the effective date for rates in UNSE's next rate case.

Table 7: UNSE's Proposed Property Tax Deferral Calculation[34]

Please describe in more detail how the property tax deferral will be calculated.

The table below provides an example of the property tax deferral calculation that will be done for each tax year until the effective date for rates in UNS Electric's next rate case.

1) Test Year Assessed Value	$59,950,520
2) Gila Assessed Value Reduction - Successful Appeal*	$3,780,000
3) Adjusted Assessed Value (1 – 2)	$56,170,520
4) Actual Composite Rate**	12.5000%
5) Test Year Composite Rate	11.2370%
6) Deferral: Change in Composite Rate (3 x (4 – 5))	$709,411

[33] Direct Testimony of Jason Rademacher, page 17, line 12 through page 18, line 20.
[34] Direct Testimony of Jason Rademacher, page 19, lines 4-16.

Q. What is Staff's recommendation regarding the proposed property tax deferral?

A. Staff recommends accepting UNSE's proposed property tax deferral. It allows recovery for items that are beyond the control of the Company and balances the interests of consumers and shareholders.

Q. Does this conclude your direct testimony?

A. Yes.

Professional Experience and Education
Donna H. Mullinax

Summary

Mrs. Mullinax has over thirty-six years of financial, management and consulting experience. She has held the position of Vice President and Chief Financial Officer for the last 20 years and served on various Boards of Directors. She has extensive experience in project management; regulatory and litigation support; financial, administration, and human resource management. She has performed numerous financial, compliance and management audits. Mrs. Mullinax has excellent analytical skills and report writing capabilities. She has designed and implemented accounting and business systems and developed policy and procedure manuals to support those systems.

Key Qualifications and Selected Professional Experience

Financial, Administration, and Human Resource Management

As Chief Financial Officer and Vice President she is responsible for all aspects of financial, administration, and human resources. Her responsibilities include accounting, cash management, budgeting, tax planning and preparation, fixed assets, human resources, and employee benefits. Records under her control have been subject to an IRS compliance audit with no findings.

Project Management

Mrs. Mullinax has successfully managed numerous projects controlling cost, schedule, and scope. These projects included management, financial, and compliance audits, M&A due diligence reviews, economic viability studies, prudence reviews, and litigation/regulatory support for construction contract claims and regulatory proceedings. She works well with diverse team members and has an excellent ability to reconcile various viewpoints and establish and maintain effective working relationships among cross-functional teams.

Financial, Compliance, and Management Auditing

Mrs. Mullinax is a skilled auditor. She has performed numerous financial, compliance, and management audits for governmental entities, businesses, and public utilities. As a CPA and CIA, she is knowledgeable about sound internal control processes and procedures and has made numerous recommendations for modifications to provide reasonable assurance regarding the achievement of objectives related to (1) effectiveness and efficiency of operations; (2) reliability of financial records, and (3) compliance with laws and regulations.

She has also conducted detailed base rates revenue requirements and rider compliance audits. She has analyzed financial information and budget projections, performed risk identification, and evaluated performance against industry benchmarks. Her extensive professional experience allows her to effectively analyze and evaluate methods and procedures and to thoroughly document her findings. She has successfully testified to her audit findings.

- On behalf of the Connecticut Public Utilities Regulatory Authority, Diagnostic Management Audit of Yankee Gas Services Company. June 2014-April 2015. Lead Auditor responsible for the scope areas of accounting and financial reporting, internal audit practices, and capital/O&M budgeting.

Professional Experience and Education
Donna H. Mullinax

- Before the Nebraska Public Service Commission (NEPSC) on behalf of the Public Advocate of Nebraska

  - NEPSC Application NG-0078.01, System Safety and Integrity Rider (SSIR) of SourceGas Distribution, LLC, November 2014 – February 2015
  - NEPSC Application NG-0078.02, System Safety and Integrity Rider (SSIR) of SourceGas Distribution, LLC, October 2015 - present

  Project Manager and Lead Auditor. Led the review of the Company's applications for a system safety and integrity rider for compliance to the Commission directives. The reviews included a detailed mathematical verification and validation of support for the revenue requirements model and reviews of proposed plant to be placed in service and the verification of planned versus actually plant placed in service for the prior year. Summarized the transactional testing results and calculated the impact to the customer charge. Drafted the report including documentation of findings, conclusions, and recommendations and coordinated the accumulation of work papers to thoroughly support all work.

  - NEPSC Application NG-0072.01, Infrastructure System Replacement Cost Recovery Charge (ISR Rider) of SourceGas Distribution, LLC May 2014-August 2014.
  - NEPSC Application No. NG-0074, Infrastructure System Replacement Cost Recovery Charge (ISR Rider) of Black Hills/Nebraska Gas Utility Company, LLC, d/b/a Black Hills Energy, July-November 2013.
  - NEPSC Application No. NG-0072, Infrastructure System Replacement Cost Recovery Charge (ISR Rider) of SourceGas Distribution, LLC March 2013-May 2013.

  Project Manager and Lead Auditor. Led the review of the Company's applications for an infrastructure system replacement cost recovery charge (ISR Rider) for compliance to the Nebraska Natural Gas Regulation Act. The reviews included a detailed mathematical verification and validation of support for the revenue requirements model and reviews of plant work order supporting the requested recovery of utility plant in service. Summarized the transactional testing results and calculated the impact to the customer charge. Drafted the report including documentation of findings, conclusions, and recommendations and coordinated the accumulation of work papers to thoroughly support all work.

- On behalf of the Staff of the Public Utilities Commission of Ohio (PUCO)

  - Case No. 14-1628-EL-RDR: Delivery Capital Recovery (DCR) Rider Audit of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company (collectively, Companies), December 2014-April 2015. Project Manager and Lead Auditor.
  - Case No. 13-2100-EL-RDR: Delivery Capital Recovery (DCR) Rider Audit of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company (collectively, Companies), December 2013-May 2014. Project Manager and Lead Auditor.
  - Case No. 13-0419-EL-RDR: Distribution Investment Rider (DIR) Audit of Columbus Southern Power Company and Ohio Power Company, d/b/a AEP-Ohio, March-August 2013. Project Manager and Lead Auditor.
  - Case No. 12-2855-EL-RDR: Delivery Capital Recovery (DCR) Rider Audit of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo

Edison Company (collectively, Companies), December 2012-July 2013. Project Manager and Lead Auditor.

- Case No. 11-5428-EL-RDR: DCR Rider Audit of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company (collectively, Companies), November 2011 - May 2012. Project Manager and Lead Auditor.

  Led the review to ensure the accuracy and reasonableness of the Companies' compliance with its Commission-approved infrastructure cost recovery rider filings. The review included a detailed mathematical verification and validation of the support of the riders' revenue requirements model, development of sensitivity analysis that supported the PPS sampling techniques used to isolate specific plant work order for further testing. Summarized the transactional testing results and calculated the impact to the rider's revenue requirements. Detailed variance analyses of historical data with investigations into any significant changes. Drafted the report including documenting findings, conclusions, and recommendations and coordinated the accumulation of work papers to thoroughly support all work performed.

- Case # 08-0072-GA-AIR Columbia Gas of Ohio for an increase in gas rates, April-August 2008
- Case # 07-0829-GA-AIR Dominion East Ohio for an increase in gas rates, November 2007-July 2008
- Case # 07-0589-GA-AIR Duke Energy Ohio for an increase in gas rates. November 2007-Februrary 2008

  Lead Auditor and assistant project manager. Performed a comprehensive rate case audit of companies' gas rate filings to validate the filings, provided conclusions and recommendations concerning the reliability of the information, and supported Staff in its evaluation of the reasonableness of the filing. Drafted the report including documenting findings, conclusions, and recommendations and coordinated the accumulation of work papers to thoroughly document work performed.

- ❖ On behalf of the Massachusetts Department of Public Utilities, Case No. D.P.U. 08-110, regarding the Petition and Complaint of the Massachusetts Attorney General for an Audit of New England Gas Company (NEGC), February-August 2010. Lead Auditor and Assistant Project Manager. Conducted a management audit on how NEGC manages its accounting and financial reporting functions and whether sufficient controls are in place to ensure that the information included in the company's filings can be reasonably relied upon for setting rates – areas reviewed included general accounting, financial reporting, and internal controls; plant accounting; income tax; accounts receivable; accounts payable; cash management; payroll; cost allocations; and capital structure. Developed the report including documenting findings, conclusions, and recommendations and coordinated the accumulation of work papers to thoroughly document work performed.

- ❖ On behalf of the Staff of the Connecticut Public Utilities Regulatory Authority (PURA), Docket 07-07-01: Diagnostic Management Audit of Connecticut Light and Power Company, July 2008-June 2009, Lead Auditor and Assistant Project Manager. Performed an in-depth investigation and assessment of the company's business processes, procedures, and policies relating to the management operations and system of internal controls of the company's executive management, system operations, financial operations, marketing operations, human resources, customer service, external relations, and support services. In addition, supported an in-depth review of the development and implementation process of the company's new customer information system. Developed the report including documenting findings, conclusions, and recommendations and coordinated the accumulation of work papers to thoroughly document all findings.

❖ Before the Oregon Public Utilities Commission (ORPUC), Docket No. UP 205: Examination of NW Natural's Rate Base and Affiliated Interests Issues, Co-sponsored between NW Natural, ORPUC Staff, Northwest Industrial Gas Users, Citizens Utility Board, August 2005-January 2006, Lead Auditor and Assistant Project Manager. Examined NW Natural's Financial Instruments, Deferred Taxes, Tax Credits, and Security Issuance Costs to ensure Company compliance with orders, rules, and regulations of the ORPUC and with Company policies. Developed the report including documenting findings, conclusions, and recommendations and coordinated the accumulation of work papers to thoroughly document work performed.

Partial List of Reports and Publications

- Examination of SourceGas Distribution LLC Application for Recovery of 2015 Eligible System Safety and Integrity Costs on Behalf of the Nebraska Public Advocate, January 8, 2015
- Compliance Audit of the 2014 Delivery Capital Recovery (DCR) Riders of Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company, March 30, 2015
- Management Audit of Yankee Gas Services Company, April 3, 2015
- Examination of the Infrastructure System Replacement Cost Recovery Charge of SourceGas Distribution LLC, June 30, 2014
- Compliance Audit of the 2013 Delivery Capital Recovery (DCR) Riders of Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company, April 9, 2014
- Examination of the Infrastructure System Replacement Cost Recovery Charge of Black Hills/Nebraska Gas Utility, LLC d/b/a Black Hills Energy, October 4, 2013
- Compliance Audit of the 2012 Distribution Investment Rider (DIR) of Columbus Southern Power and Ohio Power Company d/b/a AEP-Ohio, June 19, 2013
- Examination of the Infrastructure System Replacement Cost Recovery Charge of SourceGas Distribution LLC, May 16, 2013
- Compliance Audit of the 2012 Delivery Capital Recovery (DCR) Riders of Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company, March 22, 2013
- Compliance Audit of the Delivery Capital Recovery (DCR) Riders of Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company, April 12, 2012
- Revenue Requirements Audit of New England Gas Company, May 12, 2011
- Accounting and Financial Reporting Review of New England Gas Company, August 5, 2010
- Management Audit of The Connecticut Light & Power Company, May 29, 2009
- Report of Conclusions and Recommendations on the Financial Audit of the Columbia Gas of Ohio, Inc. in Regards to Case No. 08-0074-GA-AIR, August 13, 2008

- Report of Conclusions and Recommendations on the Financial Audit of the East Ohio Gas Company d/b/a Dominion East Company in Regards to Case No. 07-0829-GA-AIR, April 16, 2008
- Report of Conclusions and Recommendations on the Financial Audit of Duke Energy Ohio, Inc. in Regards to Case No. 07-0589-GA-AIR, December 17, 2007
- Report of Conclusions and Recommendations of NW Natural's Rate Base and Affiliated Interest Issues in Support of Oregon Public Utilities Commission Docket UM1148, December 23, 2005

Regulatory and Civil Litigation

She has provided or supported civil or regulatory testimony in Arizona, Colorado, Connecticut, Delaware, Illinois, Maryland, Michigan, Missouri, New York, North Carolina, North Dakota, South Carolina, Texas, and Utah. She has also served as an advisor to public service commissioners in the District of Columbia and Connecticut. In addition to providing analytical support, she has served as an expert witness and routinely works with other highly specialized expert witnesses. She has developed defendable analyses and testimony in connection with rate cases, audit findings, and other regulatory issues. She has also supported various civil litigations including delay and disruption construction claims and financial fraud. She has supported counsel with interrogatories, depositions, and hearings/trials support.

Regulatory Proceedings

❖ Before the Nebraska Public Service Commission (NEPSC) on behalf of the Public Advocate of Nebraska

- NEPSC Application NG-0078, SourceGas Distribution, LLC May 2014-November 2014.

  Project Manager, Lead Auditor, and Expert Witness. Led the review of the Companies' applications to replace its infrastructure system replacement (ISR) cost recovery charge with a prospective System Safety and Integrity Rider (SSIR). The review included an analysis of the Company's projected revenue deficiency that lead to the request for the prospective SSIR. The SSIR was subject to a detailed mathematical verification and validation of support for the revenue requirements model and reviews of proposed projects supporting the requested recovery of utility plant in service. Testimony on the analysis will be filed in August 2014.

❖ On behalf of the Commissioners and Staff of the District of Columbia Public Service Commission (DCPSC)

- Formal Case No. 1103 Potomac Electric Power Company (Pepco) base electric rate case, June 2013-present. Project Manager.
- Formal Case No. 1093 Washington Gas Light Company (WGL) base gas rates case, July 2011-July 2013. Project Manager.
- Formal Case No. 1087 Pepco base electric rates case, September 2011-December 2012
- Formal Case No. 1076 Pepco base electric rates case, July-December 2009
- Formal Case No. 1053 Pepco base electric rates case, February 2007-June 2008

  Lead Consultant advising Commissioners and Staff of the Office of Technical and Regulatory Analysis regarding Company's proposed rate base, net operating income and revenue requirements. Assessed the companies' and Intervenors' positions on various issues and provided defendable recommendations for the Commissioners' consideration. Developed "what if" revenue requirement model used during Commission deliberations to analyze the impact of various adjustments. Supported the drafting of the Commission's Order and supplied the revenue requirement schedules to support the final decision. Supported the Commissioners' legal team in addressing motions for reconsideration.

- Formal Case No. 1106 Washington Gas Light Company (WGL) Interruptible Service Customer Class rates and related issues, February 2014-present. Lead Consultant and Project Manager. Led the effort to review the Distribution Charge Adjustment and proposed changes as well as the review of taxes, depreciation, and cash working capital within the customer class cost of service study.
- Formal Case No. 1032 Pepco base electric rates case, January-March 2005. Senior Technical Consultant and Assistant Project Manager. Reviewed and evaluated Company's compliance filings for class cost of service and revenue requirements for distribution service pursuit to a settlement approved in May 2002. Provided analysis and recommended adjustments to Staff. Proceeding was settled in anticipation of a full rate case for rates to be effective August 8, 2007.
- Formal Case No. 1016 WGL natural gas base rates case, June-December 2003. Senior Technical Consultant and Project Manager. Analyzed and recommended adjustments regarding the company's proposed increase to base rates – advised the Commission on party positions during deliberations Review and evaluation of company's depreciation study filed with the Commission.

- Before the Missouri Public Service Commission, Case No. HR-2011-0241, on behalf of the City of Kansas City: Veolia Energy Company 2011 and 2012 electric base rates case, July-September 2011. Senior Technical Consultant. Analyzed Company's proposed net operating income, rate base, and revenue requirements. Supported testifying witness with drafted testimony and development of a model to calculate an alternative revenue requirement incorporating recommended adjustments.
- Before the North Dakota Public Service Commission, Case No. PU-10-657/PU-11-55: Northern States Power Company (NSP) 2011 and 2012 electric base rates case, April-November 2011. On behalf of the Commission Staff, Lead Consultant and Assistant Project Manager. Led the analysis of NSP's rate increase filings and supported adjustments for the Commission's consideration. Developed a model to calculate the appropriate revenue requirements and exhibits to support Staff recommended adjustments.
- Before the Connecticut Public Utilities Regulatory Authority (PURA), Docket 10-02-13: Aquarion Water Company base rates case, on behalf of the PURA, April-August 2010. Senior Technical Consultant and Assistant Project Manager. Reviewed the expense component of the company's revenue requirement and recommended adjustments for Staff consideration.
- Before the of the Delaware Public Service Commission on behalf of Staff
  - Docket No. 09-414: Delmarva Power & Light Company (DPL) electric base rates case, September 2009-May 2010. Expert Witness and Assistant Project Manager. Analyzed the company's rate increase filings and provided testimony offering adjustments for the Commission consideration related to the rate base and revenue requirements.

Professional Experience and Education
Donna H. Mullinax

- Docket No. 06-284: DPL's gas base rates case, October 2006-March 2007. Senior Technical Consultant and Assistant Project Manager. Analyzed the Company's filings, checked the mathematical accuracy of the Company's revenue requirements calculations, and provided analytical support to testifying witness.

❖ Before the Michigan Public Service Commission (MIPSC) on behalf of the Michigan Attorney General

- Case No. U-15506: Consumers Energy Company base gas rates case, May-November 2008. Expert Witness and Assistant Project Manager. Analyzed the company's rate increase filings and provided testimony offering adjustments for the Commission consideration related to the rate base and revenue requirements – proceeding was settled through negotiations.

- Case No U-15244 Detroit Edison electric base rates case, September 2007-October 2008.

- Case No. U-15245 Consumers Energy Company base gas rates case, July 2007-April 2008.

  Senior Technical Consultant and Assistant Project Manager. Analyzed the Company's filings, checked the mathematical accuracy of the Company's revenue requirements calculations, and provided analytical support to testifying witness.

- Case No. U-14547 Consumers Energy Company base gas rates case, December 2005-April 2006. Expert Witness and Assistant Project Manager. Analyzed Company's rate increase filings and provided testimony offering adjustments for Commission consideration related to the rate base and revenue requirements.

❖ Before the Maryland Public Service Commission (MDPSC)

- Case No. 9092 Pepco electric base rates case, on behalf of the Staff of the MDPSC, December 2006-June 2007. Expert Witness and Assistant Project manager. Analyzed Company's rate increases filings and provided direct and rebuttal testimony offering adjustments for the Commission consideration related to the rate base and revenue requirements.

- Case No. 9062 Chesapeake Utilities Corporation gas base rates case, on Behalf of the Maryland Office of People's Counsel, May-August 2006. Expert Witness and Assistant Project Manager. Analyzed Company's rate increase filings and provided testimony offering adjustments for the Commission consideration related to the rate base and revenue requirements – participated in settlement negotiations that were ultimately accepted by all parties.

❖ Before the Illinois Commerce Commission, Case No. 05-0597, on behalf of the Illinois Citizens Utility Board, Cook County State Attorney's Office and City of Chicago, November 2005-May 2006. Senior Technical Consultant and Assistant Project Manager. Analyzed the Company's filings, checked the mathematical accuracy of the Company's revenue requirements calculations, and provided analytical support to testifying witness.

❖ Before the Hawaii Public Utilities Commission (HPUC), Docket No. 05-0075: Instituting a Proceeding to Investigate Kauai Island Utility Cooperative's Proposed Revised Integrated Resource Planning and Demand Side Management Framework, On behalf of the Staff of the HPUC, June-November 2005. Senior Technical Consultant and Assistant

Professional Experience and Education
Donna H. Mullinax

Project Manager. Conducted and reported on the results of an industry survey of other cooperatives and Commissions to obtain an overview of how other entities approach the specific issues identified within this docket.

- Before the Public Utilities Commission of the State of Colorado (COPUC), Docket No. 04A-050E: Review of the Electric Commodity Trading Operations of Public Service Company of Colorado (PSCo), On behalf of the COPUC Staff, March-September 2004. Expert Witness and Assistant Project Manager. Performed a transaction audit of PSCo's electric commodity trading operations and submitted testimony describing the process used to conduct the investigation, a summary of the audit findings, and discussion of the significance of the findings.

- Before the New York Public Service Commission, Case No. 00-E-0612: Proceeding on Motion of the Commission to Investigate the Forced Outage at Consolidated Edison Company of New York, Inc.'s Indian Point No. 2 Nuclear Generation Facility, On behalf of Consolidated Edison Company of New York, Inc., October 2000-September 2003. Project Manager. Supervised cross functional teams to assist scheduling and nuclear engineering experts with responses to interrogatories and the development of three comprehensive rebuttal testimonies on the prudence of extended outages at the Indian Point 2 nuclear power plant. The proceeding settled prior to filing of testimony.

Civil Litigation

- ADF Construction vs. Kismet, On Behalf of ADF Construction, December 2003-February 2004. Assistant Project Manager for a delay and disruption construction claim related to a large hotel complex in North Carolina – worked with scheduling experts to determine schedule delay and disruption and calculated related damages.

- On behalf of New Carolina Construction, July 2002-January 2003
  - New Carolina Construction vs. Atlantic Coast
  - New Carolina Construction vs. Acousti

  Project Manager for a delay and disruption claim related to construction of a large high school complex in South Carolina – worked with scheduling experts to determine schedule delay and disruption and calculated related damages. Claim was settled out of court.

- State of Nevada Bureau of Consumer Protection, September-December 2003. Assistant Project Manager for damage assessment project related to potential litigation regarding the Western Market Manipulation.

- Oakwood Homes, On behalf of Oakwood Homes, February 1999-May 2000. Assistant Project Manager for a delay and disruption claim related to the construction of a large manufacturing facility in Texas – worked with scheduling experts to determine schedule delay and disruption and calculated related damages. Dispute was settlement through mediation.

- McMillan Carter, On behalf of McMillan Carter, June-September 2002. Project Manager for a delay and disruption claim related to construction of a large high school complex in North Carolina – worked with scheduling experts to determine schedule delay and disruption and calculated related damages. Claim was settled out of court.

- Fluor Daniel Inc. vs. Solutia, Inc., On behalf of Fluor Daniel, May 2000-August 2001. Assistant Project Manager for a delay and disruption construction claim related to large chemical processing facility in Texas – worked with scheduling experts to determine schedule delay and disruption and calculated related damages. Dispute proceeded through mediation.

- First National Bank of South Carolina vs. Pappas, On Behalf of First National Bank of South Carolina, 1991-1992. Civil litigation, deposed during pre-trial discovery on analytical findings related to check kiting and fraudulent loan applications. Supported counsel and expert witnesses during civil proceeding.
- First Union vs. Pappas, On Behalf of First Union, 1991-1992. Civil litigation, deposed during pre-trial discovery on analytical findings related to check kiting and fraudulent loan applications. Dispute was settled out of court.

Testimony proffered

Before the Colorado Public Utilities Commission
- Public Service Company of Colorado - Docket No. 04A-050E

Before the Delaware Public Service Commission
- Delmarva Power & Light Company - Docket No. 09-414

Before the Maryland Public Service Commission
- Potomac Electric Power Company - Case No. 9092
- Chesapeake Utilities Corporation - Case No. 9062

Before the Michigan Public Service Commission
- Consumers Energy Company - Case No. U-15506
- Consumers Energy Company - Case No. U-14547

Before the Public Service Commission of Nebraska
- SourceGas Distribution LLC – Docket No. NG-0078

System Implementation

Mrs. Mullinax has worked with various business and local governmental entities to design and implement accounting and business systems that addressed real world problems and concerns. She has developed accounting policy and procedure manuals for county governments, a library, and a water utility.

Professional Experience

Blue Ridge Consulting Services, Inc.: 2004 - Present
Vice President and Chief Financial Officer
Senior Technical Consultant / Expert Witness

Hawks, Giffels &Pullin, Inc.: 1993 - 2004
Vice President and Chief Financial Officer
Executive Consultant
Controller

Cherry, Bekaert & Holland, CPAs: 1991 - 1993
Accounting Supervisor
Senior Accountant
Staff Accountant

Smith, Kline and French Pharmaceutical Company: 1988 - 1991

Professional Experience and Education
Donna H. Mullinax

Professional Sales Representative

Milliken & Company: 1979 - 1988
Quality Assurance Manager
Technical Cause Analyst
Department Manager

Professional Certification

Certified Public Accountant (CPA), State of South Carolina - 1993
Certified Financial Planner (CFP) - 1994
Certified Internal Auditor (CIA) - 2006
Chartered Global Management Account (CGMA) - 2012

Professional Affiliations

Member of the American Institute of Certified Public Accountants (AICPA)
Member of the South Carolina Association of Certified Public Accountants (SCACPA)
Member of the Institute of Internal Auditors (IIA)
Member of the Western Carolinas Chapter of the Institute of Internal Auditors (WCIIA)

Education

Clemson University, B.S. Administrative Management with honors, 1978
Clemson University, M.S. in Management, 1979
College for Financial Planning, 1994
NARUC Utility Rate School, 32nd Annual Eastern

ARIZONA CORPORATION COMMISSION

Docket No. E-04204A-15-0142

UNS Electric, Inc.
List of Schedules

Line #	Schedule	Description
1	Schedule A	Computation of Increase in Gross Revenue Requirement
2	Schedule A.1	Computation of Revenue Conversion Factor
3	Schedule B	Original Cost and RCND Adjusted Rate Base
4	Schedule C	Adjusted Net Operating Income
5	Schedule D	Cost of Capital
6	Schedule D.1	Impact of Recommended Cost of Captial on Company's Proposed Revenue Requirements
7	Schedule E	Summary of Rate Base and Operating Income Adjustments
8	Schedule E-1	Adjustment E-1 Cash Working Capital
9	Schedule E-1 WP	Adjustment E-1 Cash Working Capital Workpaper
10	Schedule E-2	Adjustment E-2 Bad Debt Expense
11	Schedule E-3	Adjustment E-3 Injuries and Damages
12	Schedule E-4	Adjustment E-4 Payroll Expense and Payroll Taxes
13	Schedule E-5	Adjustment E-5 Incentive Compensation
14	Schedule E-5 WP	Adjustment E-5 Incentive Compensation Workpaper
15	Schedule E-6	Adjustment E-6 Directors and Officers (D&O) Liability Insurance
16	Schedule E-7	Adjustment E-7 Interest Synchronization
17	Schedule E-8	Adjustment E-8 Purchased Power and Fuel Adjustment Clause (PPFAC)
18	Schedule E-9	Adjustment E-9 OATT
19	Schedule E-10	Adjustment E-10 Gila River Deferred Cost Accumulated Depreciation

ARIZONA CORPORATION COMMISSION

UNS Electric, Inc.
Computation of Increase in Gross Revenue Requirement
ACC Jurisdictional
Test Year Ended December 31, 2014

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Schedule A
Page 1 of 1

(Thousands of Dollars)

Line	Description	Reference	UNSE Proposed Original Cost (A)	UNSE Proposed RCND (B)	UNSE Proposed Fair Value (B)	Staff Calculated Original Cost (C)	Staff Calculated RCND (E)	Staff Calculated Fair Value (D)	Difference Original Cost (E)	Difference RCND (E)	Difference Fair Value (F)
1	Adjusted Rate Base	Sch. B (ACC)	$ 272,013	$ 439,427	$ 355,720	$ 270,189	$ 437,603	$ 353,896	$ (1,824)	$ (1,824)	$ (1,824)
2	Required Operating Income (a)		$ 22,108	$ 22,108	$ 22,108	$ 19,818	$ 19,818	$ 19,818	$ (2,290)	$ (2,290)	$ (2,290)
3	Adjusted Orperating Income	Sch. C (ACC)	$ 8,045	$ 8,045	$ 8,045	$ 8,537	$ 8,537	$ 8,537	$ 492	$ 492	$ 492
4	Operating Income Deficiency		$ 14,064	$ 14,064	$ 14,064	$ 11,281	$ 11,281	$ 11,281	$ (2,782)	$ (2,782)	$ (2,782)
5	Gross Revenue Conversion Factor		1.6084	1.6084	1.6084	1.6070	1.6070	1.6070			
6	Increase in Gross Revenue Requirement		$ 22,621	$ 22,621	$ 22,621	$ 18,128	$ 18,128	$ 18,128	$ (4,493)	$ (4,493)	$ (4,493)
7	Weighted Average Cost of Captial	Schedule D	7.67%	7.67%	7.67%	7.22%	7.22%	7.22%			
8	Fair Value Adjustment		0.46%	-2.64%	-1.45%	0.12%	-2.69%	-1.62%			
9	Required Rate of Return	Schedule D	8.13%	5.03%	6.22%	7.33%	4.53%	5.60%			
10	Return on Equity		10.35%			9.50%					
	Revenue Increase and Estimated Percentage Rate Increase (Decrease)										
11	Electric Retail Revenues - Current Rates	Sch. C (ACC)	$ 147,107		$ 147,107	$ 154,888		$ 154,888	Staff Revenue from Schedule C		
12	With Proposed Base Rate Increase	Line 6 + Line 10	$ 169,728		$ 169,728	$ 173,016		$ 173,016			
13	Percent Retail Revenue Increase		15.4%		15.4%	11.7%		11.7%			

Notes and Source
Column A and B: UNSE filing, Schedule A-1

[a] Required Operating Income

	UNSE Proposed	
Adjusted OCRB Rate Base	$ 272,013	
Weighted Average Cost of Captial	7.67%	
Required Income Before FV Adjustment	$ 20,854	$ 20,854
Adjusted FV Rate Base	$ 355,720	
Adjusted OCRB Rae Base	$ 272,013	
Difference	$ 83,707	
Return on FV Increment (b)	1.50%	
Required Income on FV Increment	$ 1,256	$ 1,256
Required Operating Income		$ 22,108

(b) From 2015 UNSE Rev Req Model.xlsm; Cover; Line 31

ARIZONA CORPORATION COMMISSION

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Schedule A.1
Page 1 of 1

UNS Electric, Inc.
Computation of Revenue Conversion Factor

Test Year Ended December 31, 2014

Line	Description	Company Proposed (A)	Staff Adjustment (B)	Staff Proposed (C)
1	Gross Revenue	100.00%		100.00%
2	Less: Uncollectible Revenue (a)	0.3438%	-0.0895%	0.2543%
3	Taxable Income as a Percent	99.66%		99.75%
4	State Income Tax Rate	5.48%		5.48%
5	Federal Effective Income Tax Rate [b]	32.14%		32.14%
6	Total Effective Tax Rate	37.61%		37.613%
7	Total Effective Tax Rate Adjusted for Uncollectibles	37.48%		37.52%
8	Change in Net Operating Income	62.17%		62.23%
9	Gross Revenue Conversion Factor	1.6084	(0.0014)	1.6070

Notes and Sources
Column A: UNSE filing, Schedule C-3

(a) Average Retail Expense Ratio from Bad Debt Adjustment
(b)

Federal Effective Income Tax Rate (1-State Rate*Federal Rate)	Company Proposed (A)	Staff Proposed (C)
1-State Income Tax Rate	94.53%	94.53%
Federal Income Tax Rate	34.0%	34.0%
Federal Effective Inocme Tax Rate	32.14%	32.14%

ARIZONA CORPORATION COMMISSION

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Schedule B
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UNS Electric, Inc.
Original Cost and RCND Adjusted Rate Base
ACC Jurisdictional
Test Year Ended December 31, 2014

(Thousands of Dollars)

		Original Cost			RCND		
Line	Description	As Adjusted by UNSE (A)	Staff Adjustments (B)	As Adjusted by Staff (C)	As Adjusted by UNSE (D)	Staff Adjustments (E)	As Adjusted by Staff (F)
1	Gross Utility Plant in Service	$ 664,701		$ 664,701	$ 1,169,067		$ 1,169,067
2	Less: Accumulated Depreciation	296,961	2,000	298,961	561,911	2,000	563,911
3	Net Utility Plant in Service	367,740	(2,000)	365,740	607,156	(2,000)	605,156
4	Citizens Acquisition Discount	(95,156)		(95,156)	(170,847)		(170,847)
5	Less: Accum. Amort. - Citizens Acq. Discount	(36,098)		(36,098)	(69,678)		(69,678)
6	Net Citizens Acquisition Discount	(59,058)	-	(59,058)	(101,169)	-	(101,169)
7	Total Net Utility Plant	308,682	(2,000)	306,682	505,987	(2,000)	503,987
8	Customer Advances for Construction	(3,833)		(3,833)	(4,268)		(4,268)
9	Customer Deposits	(4,428)		(4,428)	(4,428)		(4,428)
10	Other (ITC)	(422)		(422)	(422)		(422)
11	Accumulated Deferred Income Taxes	(35,161)		(35,161)	(64,617)		(64,617)
12	Total Deductions	(43,844)	-	(43,844)	(73,735)	-	(73,735)
13	Allowance for Working Capital	7,175	176	7,351	7,175	176	7,351
14	Regulatory Assets	-		-	-		-
15	Regulatory Liabilities	-		-	-		-
16	Total Rate Base	$ 272,013	$ (1,824)	$ 270,189	$ 439,427	$ (1,824)	$ 437,603

Notes and Source
Columns A and D: UNSE filing, Schedule B-1
Columns B and E: See Schedule E

	Fair Value Calculation (Per Company)		
17	Original Cost	$ 272,013	
18	RCND	$ 439,427	
19	Total	$ 711,440	
20	Average (Fair Value)	$ 355,720	Used in Schedule A
	Fair Value Calculation (Per Staff)		
21	Original Cost	$ 270,189	
22	RCND	$ 437,603	
23	Total	$ 707,792	
24	Average (Fair Value)	$ 353,896	Used in Schedule A

ARIZONA CORPORATION COMMISSION

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Schedule C
Page 1 of 1

UNS Electric, Inc.
Adjusted Net Operating Income
ACC Jurisdictional

Test Year Ended December 31, 2014
(Thousands of Dollars)

Line	Description	As Adjusted by UNSE (A)	Staff Adjustment (B)	As Adjusted by Staff (C)
	Operating Revenues			
1	Electric Retail Revenues	$ 147,107	$ 7,782	$ 154,888
2	Sales for Resale	(0)	-	(0)
3	Other Operating Revenues	1,828	-	1,828
4	Total Operating Revnues	$ 148,935	$ 7,782	$ 156,716
	Operating Expenses			
5	Fuel, Purchased Power, and Transmission	$ 77,522	$ 7,762	$ 85,284
6	Other Operations and Maintenance Expense	42,868	(782)	42,085
7	Depreciation and Amortization	13,060	-	13,060
8	Taxes Other than Inocme Taxes	6,149	(9)	6,139
9	Income Taxes	1,291	320	1,611
10	Total Operating Expenses	$ 140,889	$ 7,290	$ 148,180
11	Operating Income	$ 8,045	$ 491	$ 8,537

Notes and Sources
Column A: UNSE filing, Schedule C-1
Column B: Staff Schedule E

ARIZONA CORPORATION COMMISSION

UNS Electric, Inc.
Cost of Capital
Test Year Ended December 31, 2014

(Thousands of Dollars)

Line	Description (A)	Reference (B)	Amount (B)	Percent (C)	Cost Rate (E)	Rate of Return (F)
	UNSE'S PROPOSED					
	UNSE Proposed Adjusted Fair Value Rate Base					
1	Original Cost Rate Base (OCRB)	Schedule B	272,013			
2	Reconstructed Cost New Depreciation (RCND)	Schedule B	439,427			
3	Fair Value Rate Base (FVRB)	Average Lines 1 & 2	355,720			
4	FVRB/OCRB Multiple	Line 3/Line 1	1.30773			
	UNSE Proposed Adjusted Captial Structure for OCRB					WACC
5	Short-Term Debt		$ -	0.00%	0.00%	0.00%
6	Long-Term Bond Debt, Net	UNSE Schedule D-1	169,590	47.17%	4.66%	2.20%
7	Common Stock Equity	UNSE Schedule D-1	189,932	52.83%	10.35%	5.47%
8	Total Capital		$ 359,522	100.00%		7.67%
	UNSE Proposed Fair Value Rate of Return					FVROR
9	Short-Term Debt		$ -	0.00%	0.00%	0.00%
10	Long-Term Bond Debt, Net	Line 1 x Line 6 (Debt %	128,311	36.07%	4.66%	1.68%
11	Common Stock Equity	Line 1 x Line 7 (Equity %)	143,702	40.40%	10.35%	4.18%
12	FVRB Increment Above Original Cost	Line 3 - Line 1	83,707	23.53%	1.50%	0.35%
13	Total Capital		$ 355,720	100.00%		6.22%
	STAFF'S RECOMMENDATION					
	Staff Proposed Adjusted Fair Value Rate Base					
14	Original Cost Rate Base (OCRB)	Schedule B	270,189			
15	Reconstructed Cost New Depreciation (RCND)	Schedule B	437,603			
16	Fair Value Rate Base (FVRB)	Average Lines 14 and 15	353,896			
17	FVRB/OCRB Multiple	Line 16/Line 14	1.30981			
	Staff Proposed Adjusted Captial Structure for OCRB					WACC
18	Short-Term Debt		$ -	0.00%	0.00%	0.00%
19	Long-Term Bond Debt, Net	UNSE Schedule D-1	169,590	47.17%	4.66%	2.20%
20	Common Stock Equity	UNSE Schedule D-1	189,932	52.83%	9.50%	5.02%
21	Total Capital		$ 359,522	100.00%		7.22%
	Staff Proposed Fair Value Rate of Return					FVROR
22	Short-Term Debt		$ -	0.00%	0.00%	0.00%
23	Long-Term Bond Debt, Net	Line 14 x Line 19 (Debt %	127,451	35.83%	4.66%	1.67%
24	Common Stock Equity	Line 14 x Line 20 (Equity %)	142,738	40.13%	9.50%	3.81%
25	FVRB Increment Above Original Cost	Line 14 - Line 16	83,707	23.53%	0.50%	0.12%
26	Total Capital		$ 353,896	99.49%		5.60%

Notes and Sources

Line 21 and 24 Staff's recommended Cost of Common Stock Equity - see Staff Witness Elijah Abinah
Line 25 Staff's recommended FVRB ROR - see Staff Witness Elijah Abinah

ARIZONA CORPORATION COMMISSION

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Schedule D.1
Page 1 of 1

UNS Electric, Inc.
Impact of Recommended **Cost of Captial** on Company's Proposed Revenue Requirements

(Thousands of Dollars)

Line	Description (A)	UNSE Fair Value (B)	Staff Adjustment (C)	Staff's Position (D)
1	**Adjusted Rate Base**	$ 355,720		$ 355,720
2	Weighted Average Cost of Capital	7.67%	-0.45%	7.22%
3	Fair Value Adjustment	-1.45%	-0.17%	-1.62%
4	Required Rate of Return	6.22%	-0.62%	5.60%
5	**Return Requirement**	$ 22,097	$ (2,177)	$ 19,920
6	Operating Revenues	$ 148,935		$ 148,935
7	Operating Expenses	$ 140,889		$ 140,889
8	**Net Operating Income**	$ 8,045		$ 8,045
9	**Income Deficiency**	$ 14,053		$ 11,875
10	Revenue Conversion Factor	1.6084		1.6084
11	**Revenue Deficiency**	$ 22,603	$ (3,502)	$ 19,101
12	Revenue Deficiency Percent Change		-15.49%	

ARIZONA CORPORATION COMMISSION

UNS Electric, Inc.
Summary of Rate Base and Operating Income Adjustments
ACC Jurisdictional
Test Year Ended December 31, 2014

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Schedule E
Page 1 of 1

Line	Description	Total Staff Adjustments (A)	E-1 Cash Working Capital (B)	E-2 Bad Debt Expense (C)	E-3 Injuries & Damages (D)	E-4 Payroll Expense & Payroll Taxes (E)	E-5 Incentive Compensation (F)	E-6 D&O Liability Insurance (F)	E-7 Interest Synchronization (F)	E-8 Purchased Power & Fuel (G)	E-9 OATT (H)	E-10 Gila River Accum Depreciation (H)
	Rate Base											
1	Gross Utility Plant in Service	$ -										
2	Less: *Accumulated Depreciation*	2,000,000										2,000,000
3	Net Utility Plant in Service	(2,000,000)	-	-	-	-	-	-	-	-	-	(2,000,000)
4	Citizens Acquisition Discount	-										
5	Less: Accum. Amort. - Citizens Acq. Discount	-										
6	Net Citizens Acquisition Discount	-	-	-	-	-	-	-	-	-	-	-
7	Total Net Utility Plant	$ (2,000,000)	-	-	-	-	-	-	-	-	-	(2,000,000)
8	Customer Advances for Construction	$ -										
9	Customer Deposits	-										
10	Other (ITC)	-										
11	Accumulated Deferred Income Taxes	-										
12	Total Deductions	$ -	-	-	-	-	-	-	-	-	-	-
13	Allowance for Working Capital	$ 176,152	192,930									
14	Regulatory Assets	-						(16,778)				
15	*Regulatory Liabilities*	-										
16	Total Rate Base	$ (1,823,848)	$ 192,930	$ -	$ -	$ -	$ -	$ (16,778)	$ -	$ -	$ -	$ (2,000,000)
	Operating Revenues											
17	*Electric Retail Revenues*	$ 7,781,533										
18	Sales for Resale	-								$ 7,781,533		
19	Other Operating Revenues	-										
20	Total Operating Revenues	$ 7,781,533	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,781,533	$ -	$ -
	Operating Expenses											
21	Fuel, Purchased Power, and Transmission	$ 7,761,608										
22	Other Operations and Maintenance Expense	(782,078)		(131,640)	(333,333)	(145,533)	(151,545)	(20,028)		$ 7,781,533	$ (19,925)	
23	Depreciation and Amortization	-										
24	Taxes Other than Income Taxes	(9,473)				(440)	(9,033)					
25	Income Taxes	320,310		49,514	125,379	54,905	60,400	7,533	15,085		7,494	-
26	*Total Operating Expenses*	$ 7,290,367	$ -	$ (82,126)	$ (207,954)	$ (91,068)	$ (100,178)	$ (12,495)	$ 15,085	$ 7,781,533	$ (12,431)	$ -
27	Operating Income	$ 491,166	$ -	$ 82,126	$ 207,954	$ 91,068	$ 100,178	$ 12,495	$ (15,085)	$ -	$ 12,431	$ -

Notes and Sources

ARIZONA CORPORATION COMMISSION

UNS Electric, Inc.
Cash Working Capital

Test Year Ended December 31, 2014

(Thousands of Dollars)

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	Cash Working Capital	$ (5,197,996)	$ 192,930	$ (5,005,066)
2	**Impact to Rate Base**	$ (5,197,996)	$ 192,930	$ (5,005,066)

Notes and Sources

See CWC Workpaper

ARIZONA CORPORATION COMMISSION

UNS Electric, Inc.
Cash Working Capital Workpaper

Test Year Ended December 31, 2014

(Thousands of Dollars)

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Schedule E-1 WP
Page 1 of 1

		UNSE Proposed						Staff Recommendation	
Line	Description	Pro Forma Test Year Amount (A)	Revenue Lag Days (B)	Expense Lag Days (C)	Net Lag Days (C - D) (D)	Lead/Lag Factor (E/365) (E)	Cash Working Capital (F x B) (F)	Adjustments (G)	Cash Working Capital (H)
	Operating Expenses								
	Non-Cash Expenses								
1	Bad Debts Expense	$ 506							
2	Depreciation	11,406						$ (132)	
3	Amortization	(3,629)							
4	Deferred Income Taxes	4,627							
	Other Operating Expenses								
5	Salaries and Wages (UNSE Direct Employees)	4,616	35.59	23.33	12.26	0.0336	$ 155	(146)	(5)
6	Incentive Pay (UNSE Direct Employees)	329	35.59	267.00	-231.41	(0.6340)	(209)	(152)	96
7	Purchased Power	62,965	35.59	33.79	1.80	0.0049	311	7,782	38
8	Transmission Other	9,014	35.59	40.67	-5.08	(0.0139)	(125)	(20)	0
9	Meter Reading	574	35.59	33.67	1.92	0.0053	3		-
10	Customer Records & Collection Expenses (excluding allocations)	1,169	35.59	34.94	0.65	0.0018	2		-
11	Office Supplies and Expenses	1,005	35.59	50.89	-15.30	(0.0419)	(42)		-
12	Injuries and Damages	750	35.59	70.52	-34.93	(0.0957)	(72)	(353)	34
13	Pensions and Benefits	1,960	35.59	51.37	-15.78	(0.0432)	(85)		-
14	Support Services - TEP (Direct Labor, Burdens, System Alloc.)	6,059	35.59	44.77	-9.18	(0.0252)	(152)		-
15	Property Taxes	6,733	35.59	212.00	-176.41	(0.4833)	(3,254)		-
16	Payroll Taxes	376	35.59	12.00	23.59	0.0646	24	(9)	(1)
17	Current Income Taxes	-	35.59	0.00	35.59	0.0975	-	320	31
18	Interest on Customer Deposits	7	35.59	182.50	-146.91	(0.4025)	(3)		-
19	Other Operations and Maintenance	25,050	35.59	41.21	-5.62	(0.0154)	(386)		-
20	Total Operating Expenses	133,517				-		$ 7,290	
	Other Cash Working Capital Elements:								
21	Interest On Long-Term Debt	7,859	35.59	89.50	-53.91	(0.1477)	(1,161)		
22	Revenue Taxes and Assessments	11,717	35.59	49.43	-13.84	(0.0379)	(444)		
23	Total Cash Working Capital					Total Company	$ (5,438)		$ 194
24						ACC Jurisdiction Ratio	96%		96%
25						ACC Jurisdiction	(5,198)		$ 193
		w/o Int Synch	w/ Int Synch	Int Synch					
26.00	Current Income Taxe	305	320	15					

Notes and Sources

Lead/Lag Study from UNSE Schedule B-5, page 3 of 3

Line 24 - ACC Jurisdiction Ratio - 2015 UNSE Rev Req Model, Tab Rate Base, Cell AD 279

ARIZONA CORPORATION COMMISSION

Docket No. E-04204A-15-0142
Schedule E-2
Page 1 of 1

UNS Electric, Inc.
Bad Debt Expense

Test Year Ended December 31, 2014

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	Adjusted Retail Revenue	$ 147,106,730		$ 147,106,730
2	Three-Year Average Retail Expense Ratio	0.34375%		0.25426%
3	Pro Forma Bad Debt Expense	505,677		374,037
4	Recorded Test Year Bad Debt Expense	863,828		863,828
5	Adjust Recorded to Normalized Bad Debt	$ (358,151)	$ (131,640)	$ (489,791)
6	State Income Tax Rate	5.475%		5.475%
7	Effect on State income tax expense	$ 19,609	$ 7,207	$ 26,816
8	Federal Taxable	$ (338,542)		$ (462,975)
9	Federal Income Tax Rate	34.00%		34.00%
10	Effect on Federal income tax expense	$ 115,104	$ 42,307	$ 157,411
11	Total Income Tax		$ 49,514	
12	Total Expense	$ (223,438)	$ (82,126)	$ (305,564)
13	**Impact to Operating Income**	$ 223,438	$ 82,126	$ 305,564

Notes and Sources

Line 1 - UNSE response to UDR 1.001 Income-Bad Debt Expense

UNSE response to UDR 1.001 Income-Bad Debt Expense

Line	Description	Amount Per Company	Staff Adjustment	Amount Per Staff
	Unadjusted Retail Revenue			
14	2012	$ 160,107,465		$ 160,107,465
15	2013	160,650,785		160,650,785
16	2014	167,998,569		167,998,569
	Bad Debt Expense			
17	2012	$ 518,681		$ 518,681
18	2013	310,216		310,216
19	2014	863,828	$ (450,000)	413,828
				$ 1,242,724
	% Retail Expense to Retail Revenue			
20	2012	0.32396%		0.32396%
21	2013	0.19310%		0.19310%
22	2014	0.51419%		0.24633%
23	Average of Average Retail Expense Ratio	0.34375%		0.25446%
24	Total Unadjusted Retail Revenue	$ 488,756,820		$ 488,756,820
25	Total Bad Debt Expense	$ 1,692,724		$ 1,242,724
26	Three-Year Average Retail Expense Ratio	0.34633%		0.25426%
27	Uncollected Revenues Ratio - Schedule A.1	0.34375%		0.25426%

State and Federal Income Tax Rate - UNSE response to UDR 1.068

ARIZONA CORPORATION COMMISSION

UNS Electric, Inc.
Injuries and Damages

Test Year Ended December 31, 2014

Docket No. E-04204A-15-0142
Schedule E-3
Page 1 of 1

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	FERC 925 Injuries and Damages			
2	Year Ended 2012	$ 32,670		$ 32,670
3	Year Ended 2013	1,133,687	$ (1,000,000)	133,687
4	Year Ended 2014	27,797		27,797
5	Three-Year Average	$ 398,051	$ (333,333)	$ 64,718
6	State Income Tax Rate	5.475%		5.475%
7	Effect on State income tax expense	$ (21,793)	$ 18,250	$ (3,543)
8	Federal Taxable	$ 376,258		$ 61,175
9	Federal Income Tax Rate	34%		34%
10	Effect on Federal income tax expense	$ (127,928)	$ 107,129	$ (20,799)
11	Total Income Tax		$ 125,379	
12	Total Expense	$ 248,330	$ (207,954)	$ 40,376
13	**Impact to Operating Income**	$ (248,330)	$ 207,954	$ (40,376)

Notes and Sources

Lines 2-4 - UNSE response to UDR 1.001 Income-Injuries & Damages

State and Federal Income Tax Rate - UNSE response to UDR 1.068

ARIZONA CORPORATION COMMISSION

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Schedule E-4
Page 1 of 1

UNS Electric, Inc.
Payroll Expense and Payroll Taxes

Test Year Ended December 31, 2014

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	Total O&M Wages			
2	Year Ended 2013	$ 4,351,382	$ (145,417)	$ 4,205,965
3	Year Ended 2014	4,521,229	(134,346)	4,386,883
4	Two Year Average	$ 4,436,306	$ (139,882)	$ 4,296,424
5	Average Wage Rate Increase - 2015	2.0%		2.0%
6	Average Increase to Wages - 2015	$ 88,726		$ 85,928
7	Total Wages - 2015	$ 4,525,032		$ 4,382,352
8	Average Wage Rate Increase - 2016	2.0%		2.0%
9	Average Increase to Wages - 2016	$ 90,501		$ 87,647
10	Total Wages - 2016	$ 4,615,532		$ 4,470,000
11	Total Wage Rate Increase	$ 179,228	$ (5,651)	$ 173,577
12	Total Payroll Adjustment		$ (145,533)	
13	Effective Payroll Tax Rate	7.8%		7.8%
14	Payroll Tax Adjustment	$ 13,952	$ (440)	$ 13,512
15	Total Payroll and Payroll Tax	$ 4,629,485	$ (145,973)	$ 4,483,513
16	State Income Tax Rate	5.475%		5.475%
17	Effect on State income tax expense	$ (253,464)	$ 7,992	$ (245,472)
18	Federal Taxable	$ 4,376,021		$ 4,238,041
19	Federal Income Tax Rate	34%		34%
20	Effect on Federal income tax expense	$ (1,487,847)	$ 46,913	$ (1,440,934)
21	Total Income Tax		$ 54,905	
22	Total Expense	$ 2,888,174	$ (91,068)	$ 2,797,107
23	**Impact to Operating Income**	$ (2,888,174)	$ 91,068	$ (2,797,107)

Notes and Sources

Lines 2-11 Column A - UNSE response to UDR 1.001 Income - Payroll Expense
Line 2-3 Column B - UNSE response to UDR STF 6.12

Line 13 UNSE response to UDR 1.001 Income-Payroll Tax Expense - Effective Tax Rate = 7.8%

State and Federal Income Tax Rate - UNSE response to UDR 1.068

ARIZONA CORPORATION COMMISSION

UNS Electric, Inc.
Incentive Compensation

Docket No. E-04204A-15-0142
Schedule E-5

Test Year Ended December 31, 2014

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	Incentive Compensation	$ 313,012	$ (151,545)	$ 161,467
2	Payroll Taxes	$ 13,741	$ (9,033)	$ 4,709
3	Total Payroll Expense and Payroll Taxes	$ 326,753		$ 166,176
4	State Income Tax Rate	5.475%		5.475%
5	Effect on State income tax expense	$ (17,890)		$ (9,098)
6	Federal Taxable	$ 308,863		$ 157,078
7	Federal Income Tax Rate	34%		34%
8	Effect on Federal income tax expense	$ (105,014)		$ (53,406)
9	Total Income Tax	$ (122,904)	$ 60,400	$ (62,504)
10	Total Expense	$ 203,849	$ (100,178)	$ 103,672
11	**Impact to Operating Income**	$ (203,849)	$ 100,178	$ (103,672)

Notes and Sources

See Workpaper

ARIZONA CORPORATION COMMISSION

UNS Electric, Inc.
Incentive Compensation Workpaper

Test Year Ended December 31, 2014

Docket No. E-04204A-15-0142
Schedule E-5 WP
Page 1 of 1

Line	Description	2012 (A)	2013 (B)	2014 (C)	Average (D)	Pay Increase (E)	Total (F)
	As Filed by UNSE						
1	Incentive Compensation by FERC Account						
2	0581	$ -	$ 10,996	$ 11,558	$ 7,518	$ 595	$ 8,113
3	0583	12,228	36	-	4,088	324	4,412
4	0592	11,774	32	-	3,935	311	4,247
5	0593	10,754	7,952	7,154	8,620	682	9,302
6	0901	16,458	20,650	25,967	21,025	1,664	22,689
7	0908	(1,090)	8,238	11,652	6,267	496	6,763
8	0920	221,542	241,707	252,559	238,603	18,884	257,487
9	O&M	$ 271,666	$ 289,610	$ 308,890	$ 290,056	$ 22,956	$ 313,012
10	Non-Taxable	(118,215)	(130,669)	(131,471)			
11	Taxable	153,451	158,942	177,419			
12	Effective Payroll Tax Rate	7.8%	7.8%	7.8%			
13		$ 11,969	$ 12,397	$ 13,839	$ 12,735	$ 1,006	$ 13,741
14	Total	$ 165,420	$ 171,339	$ 191,258	$ 302,791	$ 23,963	$ 326,753
	Pay Increase - 2%						
15	2012						
16	2013	$ 5,433					
17	2014	5,433	$ 5,792				
18	2014	5,433	5,792	$ 6,178			
19	2016	5,433	5,792	6,178			
20	2017	5,433	5,792	6,178			
21	Total	$ 27,167	$ 23,169	$ 18,533	$ 22,956		
	Payroll Taxes - 2% Increase						
22	2012						
23	2013	$ 239					
24	2014	239	$ 248				
25	2014	239	248	$ 277			
26	2016	239	248	277			
27	2017	239	248	277			
28	Total	$ 1,197	$ 992	$ 830	$ 1,006		

Line	Description	2012 (A)	2013 (B)	2014 (C)	Average (D)	Pay Increase (E)	Total (F)	50/50 Sharing (G)
	Staff's Adjustment							
29	Incentive Compensation by FERC Account							
30	0581	[redacted]	$ 10,996	$ 11,558	$ 11,277	$ 893	$ 12,170	$ 6,085
31	0583		36	-	18	1	19	10
32	0592		32	-	16	1	17	9
33	0593		7,952	7,154	7,553	598	8,151	4,075
34	0901		20,650	25,967	23,308	1,845	25,153	12,576
35	0908		8,238	11,652	9,945	787	10,732	5,366
36	0920		241,707	252,559	247,133	19,559	266,692	133,346
37	O&M	$ -	$ 289,610	$ 308,890	$ 299,250	$ 23,684	$ 322,934	$ 161,467
38	Non-Taxable	[redacted]	(130,669)	(131,471)				
39	Taxable	-	158,942	177,419				
40	Effective Payroll Tax Rate	7.8%	7.8%	7.8%				
41		$ -	$ 12,397	$ 13,839	$ 8,745	$ 672	$ 9,417	$ 4,709
42	Total	$ -	$ 171,339	$ 191,258	$ 307,996	$ 24,356	$ 332,352	$ 166,176
	Pay Increase - 2%							
43	2012							
44	2013	$ -						
45	2014	5,433	$ 5,792					
46	2015	5,433	5,792	$ 6,178				
47	2016	5,433	5,792	6,178				
48	2017	[redacted]	[redacted]	[redacted]	[redacted]			
49	Total	$ 16,300	$ 17,377	$ 12,356	$ 15,344			
	Payroll Taxes - 2% Increase							
50	2012							
51	2013	$ -						
52	2014	239	$ 248					
53	2015	239	248	$ 277				
54	2016	239	248	277				
55	2017	[redacted]	[redacted]	[redacted]	[redacted]			
56	Total	$ 718	$ 744	$ 554	$ 672			

Notes and Sources

Lines 1-28 UNSE response to UDR 1.001 Income-Incentive Compensation

ARIZONA CORPORATION COMMISSION

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Schedule E-6
Page 1 of 1

UNS Electric, Inc.
Directors and Officers (D&O) Liability Insurance

Test Year Ended December 31, 2014

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	FERC 165 D&O Liability Insurance Prepaid	$ 33,557	$ (16,778)	$ 16,778
2	**Impact to Rate Base**	$ 33,557	$ (16,778)	$ 16,778
3	FERC 925 Officers & Directors Liability	$ 145,954		
4	Amount excluded by UNSE in Fortis	(105,899)		
5	D&O Liability Insurance in Test Year	40,055	$ (20,028)	20,028
6	State Income Tax Rate	5.475%		5.475%
7	Effect on State income tax expense	$ (2,193)	$ 1,096	$ (1,097)
8	Federal Taxable	$ 37,862		$ 18,931
9	Federal Income Tax Rate	34%		34%
10	Effect on Federal income tax expense	$ (12,873)	$ 6,437	$ (6,436)
11	Total Income Tax		$ 7,533	
12	Total Expense	$ 24,989	$ (12,495)	$ 12,495
13	**Impact to Operating Income**	$ (24,989)	$ 12,495	$ (12,495)

Notes and Sources

Line 1 - UNSE response to STF 10.14
Line 3 - UNSE supplemental response to UDR 1.59
Line 4 - UNSE response to STF 16.05

State Income Tax Rate - UNSE response to RUCO 1.03

ARIZONA CORPORATION COMMISSION

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Schedule E-7
Page 1 of 1

UNS Electric, Inc.
Interest Synchronization

Test Year Ended December 31, 2014

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	Rate Base	$ 272,013,000	$ (1,823,848)	$ 270,189,152
2	Interest Component of Rate of Return	2.20%		2.20%
3	Interest Attributable to Rate Base	5,981,248	(40,104)	5,941,144
4	State Income Tax Rate	5.475%		5.475%
5	Effect on State income tax expense	$ (327,473)	$ 2,195	$ (325,278)
6	Federal Taxable	$ 5,653,775		$ 5,615,866
7	Federal Income Tax Rate	34%		34%
8	Effect on Federal income tax expense	$ (1,922,284)	$ 12,890	$ (1,909,394)
9	Total Income Tax		$ 15,085	
10	Total Expense	$ (2,249,757)	$ 15,085	$ (2,234,672)
11	**Impact to Operating Income**	$ 2,249,757	$ (15,085)	$ 2,234,672

Notes and Sources

Line 1 Original Cost Rate Base from Schedule B
Line 2 Interest Component of Rate of Return - OCRB Weighted Cost of Long Term Debt on Schedule D

ARIZONA CORPORATION COMMISSION

Docket No. E-04204A-15-0142
Schedule E-8
Page 1 of 1

UNS Electric, Inc.
Purchased Power and Fuel Adjustment Clause (PPFAC)

Test Year Ended December 31, 2014

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	Test Year Adjusted Billing Detemrinants (kWh)	1,600,809,167		1,600,809,167
2	Proposed Base Cost Rate ($ per kWh)	0.048427	0.004861	0.053288
3	Base Cost of Fuel and Purchased Power	$ 77,522,386	$ 7,781,533	$ 85,303,919
4	**Electric Retail Revenues**		$ 7,781,533	
5	**Expense: Fuel, Purchased Power and Transmission**		$ 7,781,533	
6	**Impact to Operating Income**		$ -	

Notes and Sources

See Direct Testimony of Barbara Keene

State Income Tax Rate - UNSE response to RUCO 1.03

ARIZONA CORPORATION COMMISSION

Docket No. E-04204A-15-0142
Schedule E-9

UNS Electric, Inc.
OATT

Test Year Ended December 31, 2014

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	OATT	14,531,456	$ (19,925)	14,511,531
2	State Income Tax Rate	5.475%		5.475%
3	Effect on State income tax expense	$ (795,597)	$ 1,091	$ (794,506)
4		$ 13,735,859		$ 13,717,025
5	Federal Income Tax Rate	34%		34%
6	Effect on Federal income tax expense	$ (4,670,192)	$ 6,403	$ (4,663,789)
7	Total Income Tax		$ 7,494	
8	Total Expense	$ 9,065,667	$ (12,431)	$ 9,053,236
9	**Impact to Operating Income**	$ (9,065,667)	$ 12,431	$ (9,053,236)

Notes and Sources

See Direct Testimony of Eric Van Epps

State Income Tax Rate - UNSE response to RUCO 1.03

ARIZONA CORPORATION COMMISSION

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Schedule E-10
Page 1 of 1

UNS Electric, Inc.
Gila River Deferred Cost Accumulated Depreciation

Test Year Ended December 31, 2014

(Thousands of Dollars)

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	Accumulated Depreciation	$ -	$ 2,000,000	$ 2,000,000
2	**Impact to Rate Base**	$ -	$ (2,000,000)	$ (2,000,000)

Notes and Sources

See Direct Testimony of Barbara Keene

UNS ELECTRIC, INC.'S RESPONSE TO UNIFORM DATA REQUESTS - 2015 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-15-0142 May 7, 2015

UDR 1.068

Tax Rate. Please provide the Company's effective tax rate used to calculate the revenue increase attributable net income deficiencies.

RESPONSE:

The effective income tax rates used by the Company for the revenue increase are as follows:

Statutory Arizona Rate	5.500%
Arizona Apportionment Rate	99.551%
AZ Apportioned Rate	5.475%
Federal Statutory Rate, Income <$10 million	34.000%
State Tax Deduction Benefit	(1.861%)
Total Effective Income Tax Rate	37.614%

RESPONDENT:

Donye' Bonsu

WITNESS:

Jason Rademacher

UNS ELECTRIC, INC.
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED DECEMBER 31, 2014

ADJUSTMENT NAME:	Bad Debt Expense
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	February 19, 2015
PREPARED BY:	Anne Liu
CHECKED BY:	David Lewis
REVIEWED BY:	

		Total Company		ACC Jurisdictional	
FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT	DEBIT	CREDIT
904	Uncollectible Accounts		$ 358,151		$ 358,151
	ENTRY TOTAL	$0	$358,151	$0	$358,151
	NET ENTRY		$358,151		$358,151

Reason for Adjustment
To adjust retail bad debt expense expressed as a percentage of adjusted retail revenue

* Acc Jurisdictional 100%

UNS ELECTRIC, INC.
BAD DEBT EXPENSE
TEST YEAR ENDED DECEMBER 31, 2014

Test Year Revenue		
Adjusted Retail Revenue		147,106,730 (A)
3 Year Average Retail Expense Rate		0.34375%
Pro Forma Bad Debt Expense		505,677
Recorded Test Year Bad Debt Expense		863,828 2A
Adjustment Required	$	A (358,151)
Actual Bad Debt Expense		
2012	$	518,681 2C
2013		310,216 2B
2014		863,828 2A
3 Year Retail Expense Amount	$	1,692,724
Unadjusted Retail Revenue		
2012	$	160,107,465 2F
2013		160,650,785 2E
2014		167,998,569 2D
3 Year Retail Revenue	$	488,756,820
% Retail Expense to Retail Revenue		
2012		0.32395%
2013		0.19310%
2014		0.51419%
3 Year Average Retail Expense Rate		0.34375%

(A) Per Revenue Requirement Model

UNS ELECTRIC, INC.
RETAIL REVENUE AND BAD DEBT
TEST YEAR ENDED DECEMBER 31, 2014

RETAIL REVENUE

Acct$Uns Gl Ferc	Account$$Desc$$Uns Gl Ferc	Account	Account$$Desc$$Uns Gl Account	Period Year 2012	2013	2014	
0440	Residential Sales	40000	Residential Revenue	(77,294,021.20)	(81,153,196.81)	(83,961,062.94)	
0442	Com, Ind, Mining Sales	40010	Commercial Revenue	(57,052,751.44)	(58,570,727.20)	(62,320,149.77)	
0442	Com, Ind, Mining Sales	40020	Industrial Revenue	(15,937,862.99)	(14,277,920.09)	(15,202,805.47)	
0442	Com, Ind, Mining Sales	40030	Mining Revenue	(9,583,177.62)	(6,374,534.23)	(6,204,965.95)	
0444	Public Street/Hwy Lighting	40040	Pub Street & Hwy Lighting Revenue	(239,651.88)	(274,406.99)	(289,585.29)	
Grand Total				(160,107,465.13)	(160,650,785.32)	(167,998,569.42)	D
				6A, F	3B, E	34	

BAD DEBT

Acct$Uns Gl Ferc	Account$$Desc$$Uns Gl Ferc	Account	Account$$Desc$$Uns Gl Account	Period Year 2012	2013	2014	
0904	Uncollectible Accounts	45000	Allowance for Doubtful Accounts	518,680.70	310,215.85	863,827.60	A
				5A, C	4B, B	4A	

**UNS ELECTRIC, INC.'S RESPONSE TO
UNIFORM DATA REQUESTS - 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
May 7, 2015**

UDR 1.053

Bad Debt Expense. Please provide total accrued bad debt expense, recoveries, and write offs for end of year 2012, 2013 and 2014.

RESPONSE:

	Bad Debt Expense	Recoveries	Write Offs
2012	$518,681	$108,787	$507,575
2013	$310,216	$69,162	$407,940
2014	$863,828	$13,662	$395,156

Note: Bad Debt Expense results are reported from the Income Statement. The Recoveries and Write Offs are components of the 'Allowance for Doubtful Accounts' Balance Sheet account. 2014 bad debt expense includes a $450,000 specific reserve for a large mining company that filed bankruptcy during 2014.

RESPONDENT:

Brian Brumfield

WITNESS:

David Lewis

UNS ELECTRIC, INC.
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED DECEMBER 31, 2014

ADJUSTMENT NAME:	Injuries and Damages
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	February 10, 2015
PREPARED BY:	Anne Liu
CHECKED BY:	David Lewis
REVIEWED BY:	

FERC ACCT	FERC ACCOUNT DESCRIPTION	Total Company DEBIT	Total Company CREDIT	ACC Jurisdictional DEBIT	ACC Jurisdictional CREDIT
925	Injuries and Damages	$370,254		$355,542	
	ENTRY TOTAL	$370,254	$0	$355,542	$0
	NET ENTRY	$370,254		$355,542	

ACC Jurisdiction at 96.0266%

Reason for Adjustment
To adjust injuries and damages to a three year average.

UNS ELECTRIC, INC.
INJURIES AND DAMAGES
TEST YEAR ENDED DECEMBER 31, 2014

Rate Case Line	Above-the-Line

Account	Account Description	FERC	FERC Description	2012	2013	2014	3 Year Average	Test Year to Average	
50250	Workers' Compensation	0925	Injuries & Damages	55,586.04	44,482.24	37,492.76	45853.68	8,360.92	
78040	Workers' Compensation	0925	Injuries & Damages	(32,916.52)	18,204.31	(9,696.05)	(8,136.09)	1,559.96	
78100	Injuries & Damages	0925	Injuries & Damages	10,000.00	1,071,000.00	-	360,333.33	360,333.33	(A)
Grand Total				32,669.52	1,133,686.55	27,796.71	398,050.93	370,254.22	

(A) The $1M is the insurance deductible pertaining to an accident in 2013 in which a pedestrian was struck.

Note:
Query is filtered by Accounts 50250, 78040, 78100 and FERC 925 Injuries and Damages

UNS ELECTRIC, INC.
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED DECEMBER 31, 2014

ADJUSTMENT NAME:	Payroll Expense Adjustment
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	April 15, 2015
PREPARED BY:	David Lewis
CHECKED BY:	Bernadette Porter
REVIEWED BY:	

		Total Company		ACC Jurisdictional	
FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT	DEBIT	CREDIT
0548	Generation Expenses	2G $77		$77	
0553	Main Gen & Elec Plant	$9,620		$9,620	
0562	Trans-Station Expenses	$5,260		$0	
0571	Trans-Maint of OH Lines	$745		$0	
0586	Dist-Meter Expenses	$62,784		$62,784	A
0593	Dist-Maint of OH Lines	$32,226		$32,226	
0901	Cust Accounting-Supervision	$29,510		$29,510	
0908	Customer Assistance Exp	$8,519		$8,519	
0920	A&G Salaries	$30,485		$29,275	B
	ENTRY TOTAL	$179,227	$0	$172,011	$0
	NET ENTRY	$179,227			$172,011

Reason for Adjustment
To adjust payroll expense recorded in the test year by applying an estimate wage rate increase of 2% to

A = 100% ACC Jurisdiction
B = 96.0266% ACC Jurisdiction

Wages Charged to O&M

	Total Payroll (a)	Clearing Account Allocations to O&M	Exclude A&G Payroll Capitalized through A&G Loader	Total O&M Wages	
2013	23 4,016,660	54 571,273	9D (236,550)	4,351,382	A
2014	24 4,159,212	4A 682,480	6D (320,464)	4,521,229	B
	8,175,872	1,253,753	(557,014)	8,872,611	
2 Year Average O&M				4,436,305.34	
Average Wage Rate Increase		2015		2.00%	
				88,726	
				4,525,031	
Average Wage Rate Increase		2016		2.00%	
				90,501	
Total Payroll Adjustment				179,228	

A) Should Match FERC Form 1 Page 354m LN 28 Column (d) Less incentive comp (Total 90,015 Less A&G on Incentive Comp in 2013)
B) Should Match FERC Form 1 Page 354m LN 28 Column (d) Less incentive comp (Total 104,577 Less A&G on Incentive Comp in 2014)

UNSE Payroll By Function-FERC

No specific Comp requested

CC Between 512 - 649
EX Type 910 - 939

	12 Months DEC-14			Ended DEC-12
Operations - Electric				
Production				
0546 Other Prod Oper-Supervision	0.00			612.28
0548 Generation Expenses	487.48	1,683.68		22,479.61
0549 Misc Other Pw Gen Exp	1,195.28			87.25
0557 Prod Expense-Other	0.00			37.02
Transmission				
0562 Trans-Station Expenses	107,388.06			78,815.50
0563 Trans-Overhead Line Exp	4,386.88	114,932.42		11,877.00
0566 Trans-Misc Oper Expense	3,258.46			0.00
Distribution				
0581 Dist-Load Dispatching	490,418.70			450,839.26
0582 Dist-Station Expenses	28.88			733.30
0583 Dist-Overhead Line Exp	133,378.82			121,802.57
0584 Dist-Underground Line Exp	180,604.94	1,368,009.24		181,531.84
0586 Dist-Meter Expenses	376,818.04	5,914.22	Incentive Comp	477,418.28
0587 Dist-Customer Install Ex	50,713.54	1,371,823.46		39,223.72
0588 Dist-Misc Expense	134,828.51			161,720.50
0589 Dist-Rent Expense	0.00			389.78
Customer Accounting				
0901 Cust Accounting-Supervision	137,782.83	831,549.23		126,580.23
0902 Meter Rea Expense	78,384.80	12,288.81	Incentive Comp	95,141.03
0903 Cust Rec/Collection Exp	417,382.40	644,831.84		418,491.76
Customer Service & Information				
0908 Customer Assistance Exp	18,719.36	180,190.92		58,834.49
0909 Informational/Instruct Adv Exp	181,858.90	5,962.23	Incentive Comp	18,642.84
0910 Misc Cust Service/Info Exp	1,611.68	186,153.16		1,053.38
Administration & General				
0925 Injuries & Damages	(10,890.13)	937,828.94		0.00
0920 A&G Salaries	C 908,489.61	73,753.83		741,072.28
0925 Injuries & Damages	40,078.36	-347,422.58		1,379.77
0926 Pensions & Benefits	7,351.10	686,160.18		6,864.31
0930 General Advertising Exp	0.00			1,009.28
Total Operations	3,232,194.43	2,063,888.73		2,894,566.04
Maintenance - Electric				
Production				
0553 Maint Gen & Elec Plant	151,928.81	210,220.56		164,887.89
0554 Maint of Misc Oth Pwr Gen Plant	59,191.74			45,308.11
Transmission				
0571 Trans-Maint of OH Lines	16 28.32	16,278.32		5,979.13
Distribution				
0592 Dist-Maint Stn Equip	297,374.89			368,493.88
0593 Dist-Maint of OH Lines	348,468.15	700,320.53		394,129.42
0594 Dist-Maint of UG Lines	47,134.45	3,860.72		48,944.68
0595 Dist-Mnt Line Transformers	832.85	704,181.25		0.00
0596 Dist-Mnt Light/Signals	6,718.54			10,355.25
Administrative & General				
Total Maintenance	927,017.40	930,878.12		1,032,094.14
Total Operations & Maintenance	4,159,211.83	4,159,211.83		B 4,016,888.18
		104,877.61	Total Incentive	
		4,263,789.44		
		347,422.58	A&G Capitalized	
		3,916,366.85		
Electric Plant Construction				
0107 Const Work In Progress	4,231,140.26	4,231,140.26		4,731,742.88
Electric Plant Removal		347,422.58		
0108 Acum Prov-Depre/Retr	63,204.18	4,578,562.84		36,953.77
Total Electric Payroll	8,453,558.19			8,788,358.54

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FERC	%	Adjustment
548	0.04%	77.05
562	2.93%	5,238.74
586	35.03%	62,784.40
901	16.47%	28,510.12
908	4.78%	8,518.07
920	17.01%	30,406.01
553	5.37%	9,620.49
571	0.42%	744.87
593	17.98%	32,223.99
	100.00%	179,527.74

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Other Accounts			
0000 Unspecified	336,600.81		434,578.30
0000 Unspecified	1,478,304.38	1,820,838.11	1,353,104.45
0417 Rev from Nonutility Oper	2,733.82		15,289.67
UNSE Payroll Charged to Affiliates			
0000 Unspecified	25,932.57		31,298.37
0107 Const Work in Progress	178,249.99		53,410.75
0108 Accum Prov-De ctr	9.00		2,721.87
0417 Rev from Nonutility Oper	0.00		326.16
0571 Trans-Maint of OH Lines	0.00		18.01
0580 Dist-Oper Supv & Engr	0.00		1,335.66
0583 Dist-Overhead Line Exp	0.00		8,881.84
0588 Dist-Misc Expense	8,538.69		6,371.41
0593 Dist-Maint of OH Lines	125.47	828,784.04	56.00
0597 Dist-Maint of Meters	809.28		0.00
0874 Dist-Mains & Services Exp	38,773.05		27,370.32
0875 Dist-Meas & Reg Station Exp-Gen	705.98		204.03
0878 Dist-Meter Exp	50,950.38		47,890.72
0880 Dist-Other Expenses	22,501.34		18,702.24
0887 Dist-Maint of Mains	2,398.24		4,838.41
0892 Dist-Maint of Services	4,104.39		5,283.31
0893 Dist-Maint of Meters	527.94		280.71
0902 Meter Reading Expense	42,434.53		29,940.93
0903 Cust Rec/Collection Exp	399,348.37		414,988.06
0908 Customer Assistance Ex	0.00		8,490.82
0920 A&G Salaries	47,429.51		74,538.67
0926 Pensions & Benefits	8,148.09		8,229.01
Total Payroll - Utility	11,102,979.34	11,102,979.34	11,332,986.36
		204,279.92	
		11,307,259.26	

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UNS ELECTRIC INC.'S RESPONSE TO STAFF'S SECOND SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-15-0142
September 8, 2015

STF 6.12

Incentive Compensation and Payroll Expense: Direct Testimony of David L. Lewis, page 29, lines 6-10 and Income – Payroll Tax Expense.xlsm, Page 2 of the Payroll Expense workpaper includes Total O&M Wages for 2013 and 2014 used to calculate the 2 Year Average O&M:

a. Please explain the "Incentive Comp" shown on the Payroll Expense workpapers.

b. Please confirm or deny that the "Incentive Comp" shown on the Payroll Expense workpapers is the Performance Enhancement Plan (PEP) previously limited by the Commission.

c. Provide the amounts of PEP included in the Total O&M Wages for 2013 and 2014.

RESPONSE:

a. The "Incentive Comp" as show on the Payroll Expense work papers represents the amount of incentive compensation that is attributable to the labor dollars charged for each corresponding FERC account. This is also reflected in FERC Form one page 354.

b. The amount reflected in the Payroll Expense work papers only includes 50% of the non-executive PEP. The Company in this rate case is requesting 100%, see response STF 6.16 for further explanation.

c. PEP amounts included in Total O&M Wages for 2013 and 2014 are $145,417 and $134,346, respectively.

RESPONDENT:

Rigo Ramirez

WITNESS:

David Lewis

UNS ELECTRIC, INC.
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED DECEMBER 31, 2014

ADJUSTMENT NAME:	Income - Payroll Tax Expense
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	February 11, 2015
PREPARED BY:	Anne Liu
CHECKED BY:	David Lewis
REVIEWED BY:	

FERC ACCT	FERC ACCOUNT DESCRIPTION	Total Company DEBIT	Total Company CREDIT	ACC Jurisdictional DEBIT	ACC Jurisdictional CREDIT
408	Taxes Other Than Income Taxes	$13,952		$13,397	
	ENTRY TOTAL	$13,952	$0	$13,397	$0
	NET ENTRY	$13,952		$13,397.00	

100% ACC Jurisdiction

Reason for Adjustment
To adjust payroll tax expense recorded in the test year based on an annualized normal payroll level times the test year ended December 31,2014 effective employer payroll tax rate

UNS ELECTRIC, INC.
Payroll Tax Expense
Test Year Ended December 31, 2014

TEP Employer Tax - Test Year Ended December 31, 2014			
Social Security	$	2A 668,030	per Form 941
Medicare		2B 162,210	per Form 941
FUTA/SUTA		2C 8,489	per FUTA and SUTA returns
		838,729 A	

	Wages, tips and other compensation from Form 941		
1Q 2014	3A 2,865,460		
2Q 2014	4A 2,432,383		
3Q 2014	5A 3,288,891		
4Q 2014	6A 2,187,941		
	10,774,674 B	K 0.078	effective tax rate (A)
Payroll Adjustment		15A 179,227	(B)
Employer Payroll Tax Adjustment		$ 13,952 D	(A) X (B)

1A 838,729. ÷
1B 10,774,674. =
0.07784265356 G

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UNS ELECTRIC, INC.
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED DECEMBER 31, 2014

ADJUSTMENT NAME:	Income - Incentive Compensation
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	February 19, 2015
PREPARED BY:	David Lewis
CHECKED BY:	Bernadette Porter
REVIEWED BY:	

FERC ACCT	FERC ACCOUNT DESCRIPTION	Total Company DEBIT	Total Company CREDIT	ACC Jurisdictional DEBIT	ACC Jurisdictional CREDIT
0561	Dist-Load Dispatching	$2,199		$2,199	
0583	Overhead Line Expenses	$4,412		$4,412	
0592	Maintenance of Station Equipment	$4,247		$4,247	
0593	Maintenance of Overhead Lines	$5,642		$5,642	
0901	Supervision	$9,402		$9,402	
0908	Customer Assistance Expenses	$800		$800	
0920	Administrative & General Salaires	$140,893		$135,295	
0408	Payroll Taxes	$7,687		$7,381	
	ENTRY TOTAL	$175,281	$0	$169,377	$0
	NET ENTRY	$ 175,281		$169,377	

Reason for Adjustment
Incentive compensation expense is calculated by applying a wage increase of 2% for unclassified payroll to the average incentive compensation expense for the years 2012 - 2014. Only unclassified employees participate in the incentive compensation program.

The adjustment includes payroll taxes.

UNS ELECTRIC, INC.
INCENTIVE COMPENSATION EXPENSE
AVERAGE FOR THE YEARS ENDED DECEMBER 31, 2012 - 2014

					(A)	(B)	(A) - (B)
FERC	2012	2013	2014	3 Year Avg ST Incentive Comp	Normalized 3 Year Average Including 2% Increase	Test Year Ending Dec. 31, 2014	***Distribution of Incentive Comp Adjustment - Wage Increase
0581	-	10,996	11,558	7,518	8,113	5,914	2,199
0583	12,228	36	-	4,088	4,412	-	4,412
0592	11,774	32	-	3,935	4,247	-	4,247
0593	10,754	7,952	7,154	8,620	9,302	3,661	5,642
0901	16,458	20,650	25,967	21,025	22,689	13,287	9,402
0908	(1,090)	8,238	11,652	6,267	6,763	5,962	800
0920	221,542	241,707	252,559	238,603	257,487	116,594	140,893
O&M	271,666	289,610	308,890	290,056	313,012	145,417	167,595
Non-Taxable	(118,215)	(130,669)	(131,471)	(126,785)			
Taxable	153,451	158,942	177,419	163,271			
0408 FICA TAX*	11,969	12,397	13,839	12,735	13,741	6,054	7,687
Total	165,420	171,339	191,258	176,006	326,753	151,472	175,282

Pay Increase				
** % Per Year:	2%			
2012	-	-	-	
2013	5,433	-	-	
2014	5,433	5,792	-	
2015	5,433	5,792	6,178	
2016	5,433	5,792	6,178	
2017	5,433	5,792	6,178	
	27,167	23,169	18,533	22,956
Taxes				
2012	-	-	-	
2013	239	-	-	
2014	239	248	-	
2015	239	248	277	
2016	239	248	277	
2017	239	248	277	
	1,197	992	830	1,006

UNSE(0142)000253

*FICA Tax = 7.8% Effective tax rate per Payroll Tax Pro Forma

**Average wage increase of 2% for Unclassified Payroll per Payroll Adjustment Pro Forma. Only unclassified employees participate in the incentive compensation program.

***Total adjustment has been computed as the difference between the total 3-year average of 2012-2014 versus the total Incentive Compensation recorded. The adjustment has been distributed to FERC accounts based on the test year 2014 account distribution.

UNS ELECTRIC INC.'S RESPONSE TO STAFF'S SECOND SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-15-0142 September 8, 2015

STF 6.15

Incentive Compensation: Reference workpaper Income-Incentive Compensation: The workpaper for Incentive Compensation includes "Normalized 3 Year Average Including 2% Increase." The 2% increase includes increases for 2013 through 2017. Please explain the Company's rationale for including a 2% pay increase for 2017 and how these amounts are known and measureable.

RESPONSE:

Each year, Senior Officers of the Company approve a targeted merit pay increase for non-union employees, along with a range above and below the target to correlate pay with individual employee performance. In 2015, a 2% targeted merit pay increase was approved. Since 2012, the Officers have approved annual targeted pay increases of 2%, with the exception of 2013, which specified a merit pay increase of 3%. By the time the UNS Electric rate case is finalized, the 2016 targeted merit increase will have already been awarded to employees. While the 2016 and 2017 merit increases are not yet known and measurable, management currently expects that targeted merit pay increases will be similar to those approved in recent years. Additionally, the 2016 merit pay increase should be known and measurable by the time of the rate order for UNS Electric. As a result, a 2% pay increase has been assumed for 2017. This approach is consistent with the treatment approved in the Commission's rate case decisions for TEP (Decision No. 73912, dated June 27, 2013), UNS Electric's (Decision No. 74235, dated December 31, 2013), South West Gas (Decision No. 70665, December 24, 2008), and Arizona Public Service's ("APS") (Decision No. 69663, dated June 28, 2007).

RESPONDENT:

Rigo Ramirez

WITNESS:

David Lewis

**UNS ELECTRIC, INC.'S RESPONSE TO
UNIFORM DATA REQUESTS - 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
May 7, 2015**

UDR 1.034

Incentive Programs. List and describe all retirement and incentive programs available to Company officers and employees. Provide a complete copy of each incentive compensation program and all related materials. Identify the goals and targets in each year 2013-2014, and all evaluations of whether such goals were exceeded.

a. Specifically identify the cost of any SERP or similar programs directly charged or allocated.

b. State the cost by program, of each retirement program directly charged or allocated.

RESPONSE:

THE FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

Incentives:

All UNS Electric non-union employees participate in UNS's short-term incentive program ("PEP"), which is tied to annual compensation.

The PEP performance targets and weighting are based on factors that are essential for the long-term success of the Company and are identical to the performance objectives used in its performance plan for other non-union employees. In 2014, the objectives were (i) net income; (ii) O&M cost containment; and (iii) excellent operations and safe work environment, which include both quantitative and qualitative measures. The Compensation Committee selected the goals and individual weightings for the 2014 PEP to ensure an appropriate focus on profitable growth and expense control, as well as operational and customer service excellence, and process improvements. This balanced scorecard approach encourages all employees to work toward common goals that are in the interests of UNS Energy's various stakeholders. The outcomes of which all benefit our customers in the long run.

The financial and other metrics for the Company's 2014 Short-Term Incentive Compensation program were:

- Financial – 50%
    - Net Income – 40%
    - O&M Cost Containment – 10%
- Excellent Operations and Safe Work Environment – 50%

In developing the PEP performance targets, Company management compiles relevant data such as Company historic performance and industry benchmarks and makes recommendations to the Compensation Committee for a particular year, but the Compensation Committee ultimately determines the performance objectives that are adopted.

The scores from each goal are totaled and then multiplied by the targeted bonus of each employee to determine the total available dollars to be paid out. Targeted bonus percentages, as a percent of base salary, range from 3% - 14% for unclassified employees, and 20-25% for senior management level employees. Bonus percentages, as a percent of base salary, are used in the calculation of total available dollars, and actual awards may vary at management's discretion based on individual employee contribution. If a payout is achieved, employee PEP bonuses will be distributed near the end of the first quarter the following year. Please see the files listed below for the goals for each year and evaluations of yearly performance.

File Name	Bates Numbers
UDR 1.034 2013-2014 PEP Hist Prcnts-Pos-Confidential.pdf	UNSE\009684-009685
UDR 1.034 2013 PEP Goals-Confidential.pdf	UNSE\009682-009683
UDR 1.034 2014 PEP Goals-Confidential.pdf	UNSE\009686-009687

Retirement Programs:

UNS Electric employees are eligible to participate in The Pension Plan for Employees of UniSource Energy Services. Please see the file listed below for the summary plan description.

File Name	Bates Numbers
UDR 1.034 401K_SPD-Confidential.pdf	UNSE\009688-009743

Additionally, UNS Electric employees are eligible to participate in the TEP 401(k) Plan as described below:

401(k) Plan

All UNS employees participate in the TEP's 401(k) Plan, which takes advantage of Section 401(k) of the Internal Revenue Code and permits employees to voluntarily save from 1/2% to 50% of their pay, before any deduction for state or federal income taxes. The Company matches $0.50 on the dollar, up to 6% of pay saved in the 401(k) Plan for UNS Electric employees.

Employees' savings and Company matching contributions are invested in one or any combination of a selection professionally managed investment funds at the direction of the employee. Employees are eligible to join the 401(k) Plan upon their date of employment. Company matching contributions are fully and immediately vested. Please see the file listed below for the summary plan description.

File Name	Bates Numbers
UDR 1.034 UES_Plan_SPD-Confidential.pdf	UNSE\009744-009777

a. SERP expense allocated to UNS Electric and charged to FERC 0426 during the test year was $109,515.

**UNS ELECTRIC, INC.'S RESPONSE TO
UNIFORM DATA REQUESTS - 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
May 7, 2015**

b. Retirement program expense (other than SERP) directly charged or allocated to UNS Electric during the test year was as follows:

UES Union and Salaried Pension Plans (FERC 0926)	$2,300,790
UNS Electric Employee Cost of TEP 401K Plan (FERC 0926)	100,374
TEP Pension/401K (FERC 0926)	223,556
UNS Gas Pension/401K (FERC 0926)	9,744
Deferred Compensation Plan (FERC 0920)	14,467
Total	$2,648,931

RESPONDENT:

Steve Bracamonte

WITNESS:

David Lewis

**UNS ELECTRIC, INC.'S RESPONSE TO
UNIFORM DATA REQUESTS - 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
May 7, 2015**

UDR 1.062

Accounting Adjustments.

a. Please identify any aspects of the Company's accounting adjustments and revenue requirement claim that represent a conscious deviation from the principles and policies established in prior Commission Orders.

b. Identify each area of deviation, and for each deviation explain the Company's perception of the principle established in the prior Commission Orders, and the dollar impact resulting from such deviation.

c. Show which accounts are affected and the dollar impact on each account for each such deviation.

RESPONSE:

a. The only revenue requirement claims that knowingly deviate from the Commission's prior decision for UNS Electric is the "Incentive Compensation Adjustment".

b. Although the revenue requirement in UNS Electric's most recent rate case was settled and approved in Decision No. 74235 (September 30, 2013), Staff's direct testimony prior to settlement (Staff witness Ralph Smith) recommended continuing the 50% allocation for UNS Electric's incentive compensation expense to shareholders as had been ordered by the Commission in Decision No. 71914 (September 30, 2010). Decision No. 71914 sets forth the basis of the 50% allocation at pages 27-29.

   UNS Electric is requesting full recovery of the normal and recurring level of incentive compensation expense for unclassified employees and incentive compensation for officer and senior management level employees.

c. Please see supporting pro forma workpapers provided in response to UDR 1.001, specifically the files Income – Incentive Compensation.pdf, Bates Nos. UNSE\000252-000255, and Income – Incentive Compensation.xlsm, for the accounts affected and dollars impacted.

RESPONDENT:

Pricing (Bernadette Porter)

WITNESS:

David Lewis

UNS ELECTRIC, INC.'S SUPPLEMENTAL RESPONSE TO UNIFORM DATA REQUESTS - 2015 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-15-0142 September 18, 2015

UDR 1.059

Insurance Expense. Itemize each component of insurance expense included in the test year, and provide comparative information for 2013, 2014 and year-to-date 2015. Indicate the accounts and amounts in which each item of insurance expense is recorded.

RESPONSE: **May 7, 2015**

The components of insurance expense are as follows:

Description General Ledger Account	General Ledger Account	FERC	Test Year DECEMBER 2014	2013	2012	MAR-15 YTD
General Liability	78010	925	253,810	205,425	236,350	48,938
Life Insurance/LT Disability/ADD (1)	70530	926	5,257	2,458	2,759	3,608
Medical & Dental Insurance	70520	0408, 0926	2,105,030	1,740,403	1,457,025	174,413
Officers & Directors Liability	78000	925	145,954	69,423	58,996	
Property Insurance	56040	924	211,879	161,997	164,221	26,589
Workers' Compensation	50250, 78040, 78100	925	27,797	1,133,687	32,670	6,209

(1) Amounts are net of employee payroll deductions.

RESPONDENT:

Pricing (Bernadette Porter)

WITNESS:

David Lewis

SUPPLEMENTAL RESPONSE: **September 18, 2015**

As requested ion STF 10.12, the above response is hereby updated through August 2015.

Insurance Expense 2012, 2013, 2014 and YTD 2015

Description General Ledger Account	General Ledger Account	FERC	Test Year DECEMBER 2014	2013	2012	YTD 2015
General Liability	78010	925	253,810	205,425	236,350	174,925
Life Insurance/LT Disability/ADD (1)	70530	926	5,257	2,458	2,759	8,977
Medical & Dental Insurance	70520	0408, 0926	2,105,030	1,740,403	1,457,025	1,092,549
Officers & Directors Liability	78000	925	145,954	69,423	58,996	-121
Property Insurance	56040	924	211,879	161,997	164,221	118,121
Workers' Compensation	50250, 78040, 78100	925	27,797	1,133,687	32,670	-966,842

RESPONDENT:

Pricing (Bernadette Porter)

WITNESS:

David Lewis

Arizona Corporation Commission ("Commission")
Fortis Inc. ("Fortis")
Tucson Electric Power Company ("TEP")
UNS Energy Corporation ("UNS")
UNS Energy Corporation and Fortis Inc. Joint Notice of Reorganization Settlement Agreement approved in Decision No. 74689 (August 12, 2014) (the "UNS-Fortis Settlement Agreement")
UniSource Energy Services ("UES")
UniSource Energy Development Company ("UED")
UNS Electric, Inc. ("UNS Electric" or the "Company")
UNS Gas, Inc. ("UNS Gas")
UNS Electric, Inc. 2014 Rate Case Settlement Agreement approved in Decision No. 74689 (August 12, 2014) (the "2014 Settlement Agreement")

UNS ELECTRIC INC.'S RESPONSE TO STAFF'S SIXTEENTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
October 1, 2015

STF 16.05

__Officers & Directors Liability Insurance__: Reference data response to STF 1.059: Is the Officer & Directors Liability Insurance of $145,954 included within the Test Year 100% of the insurance premium expense?

RESPONSE:

Please refer to UNS Electric's response to STF 10.13. Included in the Officers & Directors Liability Insurance of $145,954 was an amount of $105,899 due to the additional run off of insurance expense that was recognized due to the merger with Fortis. These costs ($109,095 including taxes) were subsequently excluded in the pro-forma adjustment Income - Fortis Acquisition Costs.xlsm. (The referenced file can be accessed in UNS Electric's electronic data room under Data Requests\Uniform Data Requests\Attachments - 1st Set\UDR 1.001\Workpapers – Schedules\Pro Forma Adjustments.)

The net amount of Officers & Directors Liability insurance premium included in the test year was $40,055 ($145,954 less $105,899).

RESPONDENT:

Anne Liu

WITNESS:

David Lewis

UNS ELECTRIC INC.'S RESPONSE TO STAFF'S TENTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-15-0142 September 18, 2015

STF 10.14

Prepaids in CWC: Reference workpaper Rate Base-Working Captial.pdf:

a. Please provide the 13 monthly amounts for Prepaid Insurance, Account 14010, and show the amounts related to each type of insurance.

b. Please provide a detailed itemization and explanation for each item that is included in each of the 13 monthly Other Prepaids, Account 14100.

RESPONSE:

Please see **STF 10.14.xlsx** for the requested information. The Excel file is not identified by Bates numbers.

RESPONDENT:

Bernadette Porter

WITNESS:

David Lewis

UNS Electric, Inc.
Prepaid Insurance Amortization/Reconciliation Schedule
For the year ended December 31, 2013

Account 14010-0000	BEGIN DATE	END DATE	Adjusted Amount	ANNUAL PREMIUM	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AMORTIZED END-OF PERIOD	REMAINING PREPAID INSURANCE	AMORTIZED IN PRIOR YEAR
PROPERTY INSURANCE:																			
Factory Mutual Insurance Co. policy UB785	09/01/12	09/01/13		186,708.00	15,565.50	15,565.50	15,565.50	15,565.50	15,565.50	15,565.50	15,565.50	15,565.50					124,524.00	-	62,262.00
Factory Mutual Insurance Co. policy UB202	09/01/13	04/01/14		112,418.00									9,368.17	9,368.17	9,368.17	9,368.17	37,472.68	74,945.32	-
Total Property Ins					15,565.50	15,565.50	15,565.50	15,565.50	15,565.50	15,565.50	15,565.50	15,565.50	9,368.17	9,368.17	9,368.17	9,368.17	161,996.68	74,945.32	62,262.00
INJURY & DAMAGE INSURANCE:																			
AEGIS Gen Liab # XL5112801P	08/15/12	08/15/13		111,923.12	9,326.93	9,326.93	9,326.93	9,326.93	9,326.93	(0.04)							46,634.61	-	65,288.51
EIM Excess Gen Liab #252160-12GL	08/15/12	08/15/13		85,397.70	7,113.98	7,113.98	7,113.98	7,113.98	7,113.98	(0.06)							35,569.84	-	49,797.86
EIM Excess Gen Liab #252670-13GL	08/01/13	08/01/14		85,202.47									7,100.21	7,100.21	7,100.21	7,100.21	28,400.84	56,801.63	-
Willis Excess Gen Liab #XL5112802P	08/01/13	08/01/14		122,738.36									10,228.21	10,228.20	10,228.20	10,228.20	40,912.81	81,825.55	-
Sub-total					16,440.91	16,440.91	16,440.91	16,440.91	16,440.91	(0.10)	-	-	17,328.42	17,328.41	17,328.41	17,328.41	151,518.10	138,627.18	115,086.37
AON D&O Liab #	08/28/12	08/28/13		63,377.23	5,281.44	5,281.44	5,281.44	5,281.44	5,281.44	5,281.39							31,688.59	-	31,688.64
Willis D&O Liab #	08/28/13	08/28/14		67,113.74							5,592.81	5,592.81	5,592.81	5,592.81	5,592.81	5,592.81	33,556.86	33,556.88	-
Sub-total					5,281.44	5,281.44	5,281.44	5,281.44	5,281.44	5,281.39	5,592.81	5,592.81	5,592.81	5,592.81	5,592.81	5,592.81	65,245.45	33,556.88	31,688.64
Total Injury & Damage Ins					21,722.35	21,722.35	21,722.35	21,722.35	21,722.35	5,281.29	5,592.81	5,592.81	22,921.23	22,921.22	22,921.22	22,921.22	216,763.55	172,184.06	146,773.01
Total Prepaid Ins					37,287.85	37,287.85	37,287.85	37,287.85	37,287.85	20,846.79	21,158.31	21,158.31	32,289.40	32,289.39	32,289.39	32,289.39	378,760.23	247,127.38	209,037.01

Reconciliation - 14010.0000

Preliminary Beg. Balance	279,416.82
Additions / Adjustments	-
Current Month Amortization	-32,289.39
EOM Balance	247,127.43
Balance s/b Rem. Prepaid	247,127.38
Variance	0.05

Other Items - Account 14160-0000	BEGIN DATE	END DATE	Adjusted Amount	ANNUAL PREMIUM	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AMORTIZED END-OF PERIOD	REMAINING PREPAID INSURANCE	AMORTIZED IN PRIOR YEAR
Permit for 115KV Overhead Line from Tucson to Nogales	4/15/05	4/14/15		49,740.00	414.50	414.50	414.50	414.50	414.50	414.50	414.50	414.50	414.50	414.50	414.50	414.50	4,974.00	6,217.50	38,548.50
AZ Land Department Lease #071-004513-08 in Nogales	12/11/08	12/10/18		72,499.00	604.16	604.16	604.16	604.16	604.16	604.16	604.16	604.16	604.16	604.16	604.16	604.16	7,249.92	35,645.24	29,603.84
NEC Unified Solutions	11/15/11	8/31/14		58,276.25	1,765.95	1,765.95	1,765.95	1,765.95	1,765.95	1,765.95	1,765.95	1,765.95	1,765.95	1,765.95	1,765.95	1,765.95	21,191.40	14,127.32	22,957.53
NEC Unified Solutions	11/20/12	8/21/14		30,297.74	1,442.75	1,442.75	1,442.75	1,442.75	1,442.75	1,442.75	1,442.75	1,442.75	1,442.75	1,442.75	1,442.75	1,442.75	17,313.00	11,541.99	1,442.75
Ascend Analytics	5/5/12	5/4/13		60,079.50	5,006.63	5,006.63	5,006.63	5,006.67									20,026.48	-	40,053.04
Ascend Analytics (bal written-off per plant)	5/5/13	5/4/14	12/31/13	61,281.09					5,106.76	5,106.76	5,106.76	5,106.76	5,106.76	5,106.76	5,106.76	25,533.77	61,281.09	-0.00	-
Golden Valley Fire Department (Fire/EMS services for BMG)	1/1/13	3/31/13		37,592.00	12,530.67	12,530.67	12,530.66										37,592.00	-	-
Golden Valley Fire Department (Fire/EMS services for BMG)	4/1/13	6/30/13		37,592.00				12,530.67	12,530.67	12,530.66							37,592.00	-	-
Golden Valley Fire Department (Fire/EMS services for BMG)	7/1/13	9/30/13		37,592.00							12,530.67	12,530.67	12,530.66				37,592.00	-	-
WAPA Agr #DSW-06DSR11910 - BC 061 - Ops & maint of substations	10/1/12	9/30/13		111,470.00	9,289.17	9,289.17	9,289.17	9,289.17	9,289.17	9,289.17	9,289.17	9,289.17	9,289.13				83,602.49	-	27,867.51
WAPA Agr #DSW-06DSR11910 - BC 064 - Ops & maint of substations	10/1/12	9/30/13		35,959.00	2,996.58	2,996.58	2,996.58	2,996.58	2,996.58	2,996.58	2,996.58	2,996.58	2,996.62				26,969.26	-	8,989.74
WAPA Agr #DSW-06DSR11910 - BC 061 - Ops & maint of substations	10/1/13	9/30/14		144,740.35										12,061.70	12,061.70	12,061.70	36,185.10	108,555.25	-
WAPA Agr #DSW-06DSR11910 - BC 062 - Ops & maint of substation	10/1/13	9/30/14		15,894.68										1,324.56	1,324.56	1,324.56	3,973.68	11,921.00	-
WAPA Agr #DSW-06DSR11910 - BC 064 - Ops & maint of substations	10/1/13	9/30/14		23,697.79										1,974.82	1,974.82	1,974.82	5,924.46	17,773.33	-
WAPA Prepaid Expense (Long-Term Point to Point Transmission Service - Not To Be Amortized				128,558.06													-	-	-
WAPA Prepaid Expense (Long-Term Point to Point Transmission Service - Not To Be Amortized				120,750.00													-	120,750.00	-
WAPA Prepaid Expense (Long-Term Point to Point Transmission Service - Not To Be Amortized				56,350.00													-	56,350.00	-
Sempra Generation Call Option Pre-Pay - Not To be Amortized				145,000.00													-	145,000.00	-
Total				1,227,388.48	34,030.41	34,030.41	34,030.40	34,030.35	34,150.54	34,150.53	34,150.54	34,150.54	34,150.53	34,695.20	34,695.20	45,122.21	401,288.86	527,861.83	169,462.71

Reconciliation - 14160.0000

Preliminary Beg. Balance	701,882.13
Additions / Adjustments	(128,898.08)
Current Month Amortization	-45,122.21
EOM Balance	527,861.84
Balance s/b Rem. Prepaid	527,861.83
Variance	0.01

UNS ELECTRIC INC.'S RESPONSE TO STAFF'S SIXTEENTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
October 1, 2015

STF 16.14

Fortis Merger Conditions: Reference Direct Testimony of Kentton Grant, page 13, lines 17-18: Mr. Grant states the Dallas Dukes addresses Condition 62 related to service functions that are performed for UNS Electric by Fortis, UNS Energy, or TEP. Please provide a specific cite in Mr. Grant's testimony where this information is provided. If the information has not been provided, please provide.

RESPONSE:

Condition 62 was inadvertently left out of Dallas Dukes direct testimony, however the answer to the question would be as follows:

UNS Electric receives all corporate services (finance, accounting, tax, information technology services, billing, customer service, etc.) from TEP. These services are being provided by TEP in the same manner as they were in all previous rate case test years of UNS Electric. TEP did not receive corporate service from Fortis during the test year and no costs have been included in UNS Electric's cost of service in this filing.

The Company will include the Q & A's surrounding condition 62 in Dallas Dukes Rebuttal testimony.

RESPONDENT:

David Lewis

WITNESS:

Dallas Dukes

UNS ELECTRIC INC.'S RESPONSE TO STAFF'S NINETEENTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-15-0142 October 05, 2015

STF 19.1

Please provide a list of the Fortis merger conditions not identified in the current rate case proceeding, including an explanation of how those conditions have been met.

RESPONSE:

Condition No. 43 of the Settlement Agreement approved by the Commission in Decision No. 74689 (August 12, 2014) provides the following:

> *Annual Reporting – The conditions ordered by the Commission herein shall be tracked and reported annually for a period of 5 years following the close of the transaction. UNS Energy will file a report with Docket Control by April 1 of each year, beginning April 1, 2016, reporting on the prior calendar year's status of the conditions. The report will, at a minimum, provide a description of the performance of each condition that has quantifiable results. If any condition is not being met, the report shall provide proposed corrective measures and target dates for completion of such measures.*

The intent of this condition was for UNS Energy to file its first compliance report on the status of the conditions after a full calendar year (2015) after the merger. UNS Energy will be filing this report on April 1, 2016 in compliance with this condition. To the extent there are conditions that the Settlement Agreement contemplates be discussed in the rate cases of the Regulated Utilities of UNS Energy, such conditions have been identified in the current rate case proceeding as noted in the above request.

RESPONDENT:

Regulatory Services

UNS ELECTRIC INC.'S RESPONSE TO STAFF'S SECOND SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-15-0142 September 8, 2015

STF 6.22

Property Tax Deferral: Decision No. 73183: The Commission approved a variation of the UNSE's proposed tax deferral. Exhibit A: Terms and Conditions of Settlement Agreement (pages 16-17) inserted below for reference:

> *"XII. COST DEFERRAL RELATED TO CHANGES IN ARIZONA PROPERTY TAX RATE*
>
> *12.1 APS shall be allowed to defer for future recovery, in accordance with the provisions of Accounting Standards Codification ("ASC") 980 (formerly SFAS No. 71), the following portions of Arizona property tax expense above or below the test year level of $141.5 million caused by changes to the applicable Arizona composite property tax rate (not changes in the assessed value of property).*
>
> *(a) When the property tax rate increases:*
>
> *- For 2012: 25% (prorated with an assumed July 1 rate effective date);*
>
> *- For 2013: 50%; and*
>
> *- For 2014 and all subsequent years: 75%.*
>
> *(b) When the property tax rate decreases: 100% in all years.*
>
> *No interest shall be applied to the deferred balance.*
>
> *12.2 Beginning with the effective date of the Commission decision resulting from APS's next general rate case, any final property tax rate deferral that has a positive balance will be recovered from customers over 10 years and any deferral that has a negative balance will be refunded to customers over 3 years.*
>
> *12.3 The Signatories reserve the right to review APS's property tax deferrals for reasonableness and prudence such that the deferrals can be recognized in accordance with the provisions of ASC-980 (formerly SFAS No. 71)."*

a. The Commission approved thresholds on property tax rate increases before a deferral is allowed (i.e., for 2012: 25%; 2013: 50%, etc.) Is UNSE proposing recovery for any tax rate increase?

b. The Commission approved recovery of any deferral that has a positive balance to be recovered over 10 years and any deferral that has a negative balance would be refunded to customers over three years. Please explain why UNSE's situation is different than APS and why the Commission should approve recovery of any positive balance over three years instead of ten years as approved in the APS decision.

RESPONSE:

a. Yes, UNS Electric is proposing recovery for any tax rate increase or decrease.

**UNS ELECTRIC INC.'S RESPONSE TO STAFF'S SECOND SET OF DATA REQUESTS
REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
September 8, 2015**

b. UNS Electric proposes recovery of positive and negative balances over the same 3 year period as it provides the proper balance between ratepayer and shareholder interests. Commission Decision No. 73183, dated May 24, 2014, includes the following:

According to Staff, the Settlement Agreement was the product of "many hours of intense, transparent, and robust negotiations between multiple parties with divergent interests". Staff believes that there are significant benefits in the Settlement Agreement and recommends that it be adopted. [page 9, lines 18-20]

Staff argues that the Settlement Agreement appropriately balances consumer and shareholder interests. [page 19, lines 1-2]

While the Settlement Agreement as a whole may have balanced the interest of consumers and shareholders, the property tax deferral, as a stand-alone provision is not balanced. UNS Electric proposes that the Property Tax Deferral stand alone as a balanced provision.

RESPONDENT:

Jason Rademacher

WITNESS:

Jason Rademacher

UNS ELECTRIC INC.'S RESPONSE TO STAFF'S TWENTIETH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
October 9, 2015

STF 20.11

Customer Annualization: Referring to the Customer Annualization, provide the amount/impact of the loss of the two customers referenced in Mr. Jones' testimony both in terms of revenues and sales. Provide all supporting calculations and underlying documentation (i.e., monthly bills).

RESPONSE:

The total sales loss, based on the test year and adjusted for unbilled sales, is 64 GWh. The corresponding revenue amount (excluding REST, DSM, taxes and assessments) is $6.2M. See the supplement to UDR 1.001 dated October 9, 2015 for the competitively sensitive-confidential revenue summaries and the summary worksheet that calculated these amounts from the revenue summaries.

RESPONDENT:

Greg Strang

WITNESS:

Craig Jones

EXHIBIT
S-2
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
Commissioner
ANDY TOBIN
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. 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 UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND RELATED APPROVALS	DOCKET NO. E-04204A-15-0142

SURREBUTTAL

TESTIMONY

OF

DONNA H. MULLINAX

ON BEHALF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2016

TABLE OF CONTENTS

SCHEDULES

EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-15-0142

The Surrebuttal Testimony of Donna Mullinax responds to the Rebuttal Testimony of UNS Electric, Inc. ("UNSE" or "Company") witnesses Kentton C. Grant, David J. Lewis, and David G. Hutchens as summarized below:

- Modification to Capital Structure calculation changing Staff's original Fair Value Rate of Return of 5.60 percent to 5.63 percent.

- Adjustment to Injuries and Damages for Arizona Corporation Commission Jurisdiction, which changes from Staff's initial increase to Operating Income of $207,954 to an increase of $199,699, a reduction of $8,255.

- Adjustment to Incentive Compensation for Arizona Corporation Commission Jurisdiction, which changes from Staff's initial increase to Operating Income of $100,178 to an increase of $96,920, a reduction of $3,258.

- Elimination of Payroll Expense and Tax Adjustment that were initially proposed for what appeared to be a double inclusion of Incentive Compensation. The modification changes from Staff's initial increase to Operating Income of $91,068 (including Payroll Taxes) to no increase, a reduction of $91,068.

- Modification to Gila River Deferred Cost that removes the Regulatory Asset Amortization of the deferred cost. The modification increases operating income by $1,933,981.

- Flow-through adjustment to Working Capital, which changes from an increase to rate base of $192,930 to an increase of $296,489, or an increase to rate base of $103,559.

- Flow-through adjustment to Interest Synchronization, which changes from a reduction to Operating Income of $15,085 to a reduction of $14,229, or an increase of $856.

- The impact of these modifications increased Staff's initial recommended Fair Value Rate Base by $103,558 to $353.999 million.

- The impact of these modifications changes Staff's recommended increase to base rates from $18.128 million on Fair Value Rate Base to $15.360 million, or a reduction of $2,768,000.

- Comments on Company's Incentive Compensation argument

INTRODUCTION

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

A. My name is Donna H. Mullinax. I am employed as Vice President and Chief Financial Officer by Blue Ridge Consulting Services, Inc. ("Blue Ridge"). My business address is 114 Knightsridge Road, Travelers Rest, South Carolina 29690.

Q. Did you file Direct Testimony in this proceeding?

A. Yes.

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

A. My Surrebuttal Testimony is filed on behalf of the Utilities Division Staff ("Staff") of the Arizona Corporation Commission ("ACC" or "Commission").

Q. What is the purpose of the testimony you are presenting?

A. The purpose of my Surrebuttal Testimony is to respond to portions of the Rebuttal Testimony of UNS Electric, Inc. ("UNSE" or "Company") witnesses Kentton C. Grant, David J. Lewis, and David G. Hutchens and to make several adjustments to my Direct Testimony and Exhibits.

Q. Did you revise your Schedules as a result of your analysis and review of information provided by the Company?

Yes. I have revised Schedules A, B, C, D, D.1, E, E-1, E-3, E-4, E-5, E-7, and E10. For ease of reference, Attachment DHM-1 contains Schedule A through Schedule E-10, which also includes those that were not modified.

MODIFICATIONS TO STAFF'S ADJUSTMENTS

Capital Structure – Fair Value Rate of Return

Q. Please explain the change that needs to be made to your proposed Capital Structure – Fair Value Rate of Return ("FVROR") calculation.

A. As noted in Company witness Grant's Rebuttal Testimony,[1] I inadvertently included in my FVROR calculation the Company's original filed position instead of using Staff's recommended position in the weighting calculation. My original FVROR of 5.60 percent should be 5.63 percent.

Injuries and Damages

Q. Please explain the change that needs to be made to your Injuries and Damages Adjustment.

A. As noted in Company witness Lewis's Rebuttal Testimony,[2] my original calculation for Staff Adjustment E-3 Injuries and Damages did not apply the ACC Jurisdictional factor. Staff's adjustment E-3 Injuries and Damages should change from an increase to Operating Income of $207,954 to an increase to Operating Income of $199,699, a change of $8,255.

Incentive Compensation

Q. Please explain the change that needs to be made to your Incentive Compensation adjustment.

A. As noted in Company witness Lewis's Rebuttal Testimony,[3] my original calculation for Staff Adjustment E-5 Incentive Compensation did not apply the ACC Jurisdictional factor. Staff's adjustment E-5 Incentive Compensation should change from an increase to Operating Income of $100,178 to an increase to Operating Income of $96,920, a change of $3,258.

---

[1] Rebuttal Testimony of Kentton C. Grant, page 8, lines 8-17.
[2] Rebuttal Testimony of David J. Lewis, page 2, lines 11-12.
[3] Rebuttal Testimony of David J. Lewis, page 2, lines 24-25.

Payroll Expense and Payroll Taxes

Q. Please explain the change that needs to be made to Staff Adjustment E-4 Payroll Expense and Payroll Taxes.

A. As noted in Company witness Lewis's Rebuttal Testimony,[4] there was a misunderstanding between what was requested and what was provided within a data request. I interpreted the information provided to mean that Incentive Compensation was included within Payroll Expense and Payroll Taxes. After discussions with Company witness David Lewis and a detailed review of the Company's Payroll Expense and Payroll Tax work papers, I am confident that the Company has not included Incentive Compensation in both Operations & Maintenance ("O&M") Payroll and the Company's Incentive Compensation adjustments. Staff's adjustment E-4 Payroll Expense should change from an increase to Operating Income of $91,068 (including Payroll Taxes) to no increase to Operating Income, a change of $91,068.

Gila River Deferred Cost

Q. Please explain the additional adjustment made to Staff Adjustment E-10 Gila River Deferred Cost.

A. Staff witness Barbara Keene presents the addition to Staff's Gila River Deferred Cost Adjustment. In addition to the rate base adjustment included in my Direct Testimony that reduces rate base by $2,000,000, the additional adjustment increases operating income by $1,933,981.

[4] Rebuttal Testimony of David J. Lewis, page 2, lines 13-23.

FLOW-THROUGH ADJUSTMENTS

Q. Please explain what other adjustments should be made to your revenue requirements calculations as a result of your modifications?

A. There are two flow-through adjustments that need to be made: Cash Working Capital and Interest Synchronization.

Cash Working Capital

Q. Please explain the modification to Staff Adjustment E-1 – Cash Working Capital.

A. The Company's proposed rate base includes Cash Working Capital, which was developed through the preparation of a lead-lag study. With Staff's modified adjustments noted above, the expense components of the Company's lead-lag study need to be updated. Staff Adjustment E-1 Cash Working Capital changes from an increase to jurisdictional rate base of $192,930 to an increase of $296,489, or an increase to rate base of $103,559.

Interest Synchronization

Q. Please explain the modification to Staff Adjustment E-7 – Interest Synchronization.

A. The interest synchronization adjustment is a flow-through adjustment that synchronizes the rate base and cost of capital with the tax calculation. The adjustment applies the weighted cost of debt to the calculation of test year income tax expense. If any of these components are modified, the interest synchronization calculation should be updated to reflect the correct amount of synchronized interest to be included in the tax calculation. Staff Adjustment E-7 Interest Synchronization changes from a reduction to Operating Income of $15,085 to a reduction of $14,229, or a change of $856.

IMPACT OF MODIFIED ADJUSTMENTS

Q. How did your modifications impact Staff's recommended rate base?

A. Staff's recommended rate base was increased by $103,558.

Q. What is the overall impact of your modifications to Staff's recommended base rate increase?

A. The overall impact of the modifications to Staff's adjustments changes Staff's recommended base rate increase from $18.128 million on FVRB to $15.360 million, or a reduction of $2,768,000.

Q. Has the Company agreed with your recommended base rate increase?

A. Yes. Company witness Hutchens's Rebuttal Testimony stated that the Company will agree to stipulate to an $18.5 million increase to adjusted test-year non-fuel revenues.[5] This agreed to stipulation was later modified by the Gila River Deferred Cost Adjustment as addressed in Staff witness Barbara Keene's Surrebuttal Testimony.

SURREBUTTAL TO INCENTIVE COMPENSATION REBUTTAL

Q. What was the Company rebuttal in regard to Staff's adjustment to Incentive Compensation?

A. Staff Adjustment E-5 Incentive Compensation included three parts: (1) normalization using a two-year average similar to the Payroll Expense instead of the three-year average used by the Company; (2) excluding the 2017 merit increase as not known and measureable; and (3) sharing the Incentive Compensation 50/50 between ratepayers and shareholders.

[5] Rebuttal Testimony of David G. Hutchens, page 15, lines 5-7.

The Company rebutted the third part of Staff's adjustment, sharing the Incentive Compensation 50/50 between ratepayers and shareholders, stating that it strongly disagreed with the "who benefits" analysis as a tool for what percentage of recovery should be afforded to the Company. The Company argued, "[A]lmost any expense could be seen to 'benefit' both ratepayers and shareholders."[6] Therefore, the Company is maintaining its position that 100 percent of incentive compensation should be allowed and recovered from ratepayers.

Q. Why is incentive compensation different from "almost any expense?"

A. Incentive compensation is very different from "almost any expense." Unlike incentive compensation, there is less incentive to manipulate other expenses.

Q. Please elaborate.

A. Achieving Net Income or profitability goals is a major component of the Company's incentive compensation program. As pointed out in my Direct Testimony, Financial goals are weighted 50 percent of the total incentive compensation metric, with Net Income equal to 40 percent and O&M Cost Containment equal to 10 percent.

Net Income or profitability increases as expenses are reduced. Reducing expenses drives up Net Income or profitability, increasing Incentive Compensation payouts to management and benefitting shareholders at the expense of ratepayers. For example, taken to an extreme, expenses can be reduced by deferring maintenance (resulting in increased outages) and failing to adequately staff Customer Services to address customer reported outages, inquiries, or complaints.

[6] Rebuttal Testimony of David J. Lewis, page 4, lines 13-20.

As the Commission has recognized in the past, ensuring that the competing interests are balanced is important. This balance has been achieved by requiring the sharing of incentive compensation 50/50 between ratepayers and shareholders.

Q. Does this conclude your Surrebuttal testimony?

A. Yes.

ARIZONA CORPORATION COMMISSION

Docket No. E-04204A-15-0142

UNS Electric, Inc.
List of Schedules

Line #	Schedule	Description
1	**Schedule A**	**Computation of Increase in Gross Revenue Requirement - Modified**
2	Schedule A.1	Computation of Revenue Conversion Factor
3	**Schedule B**	**Original Cost and RCND Adjusted Rate Base - Modified**
4	**Schedule C**	**Adjusted Net Operating Income - Modified**
5	**Schedule D**	**Cost of Capital - Modified for FVROR Calculation Error**
6	**Schedule D.1**	**Impact of Recommended Cost of Captial on Company's Proposed Revenue Requirements - Modified**
7	**Schedule E**	**Summary of Rate Base and Operating Income Adjustments - Modified**
8	**Schedule E-1**	**Adjustment E-1 Cash Working Capital - Modified**
9	**Schedule E-1 WP**	**Adjustment E-1 Cash Working Capital Workpaper - Modified**
10	Schedule E-2	Adjustment E-2 Bad Debt Expense
11	**Schedule E-3**	**Adjustment E-3 Injuries and Damages - Modified for ACC Jurisdictional Allocation**
12	**Schedule E-4**	**Adjustment E-4 Payroll Expense and Payroll Taxes - Withdrawn**
13	**Schedule E-5**	**Adjustment E-5 Incentive Compensation - Modified for ACC Jurisdictional Allocation**
14	**Schedule E-5 WP**	**Adjustment E-5 Incentive Compensation Workpaper - Modified for ACC Jurisdictional Allocation**
15	Schedule E-6	Adjustment E-6 Directors and Officers (D&O) Liability Insurance
16	**Schedule E-7**	**Adjustment E-7 Interest Synchronization - Modified Due Change in Working Capital - Rate Base**
17	Schedule E-8	Adjustment E-8 Purchased Power and Fuel Adjustment Clause (PPFAC)
18	Schedule E-9	Adjustment E-9 OATT
19	**Schedule E-10**	**Adjustment E-10 Gila River Deferred Cost - Modified**

ARIZONA CORPORATION COMMISSION

Docket No. E-04204A-15-0142
Schedule A
Page 1 of 1

UNS Electric, Inc.
Computation of Increase in Gross Revenue Requirement - **Modified**
ACC Jurisdictional
Test Year Ended December 31, 2014

(Thousands of Dollars)

			UNSE Proposed			Staff Calculated			Difference			
Line	Description	Reference	Original Cost (A)	RCND (B)	Fair Value (B)	Original Cost (C)	RCND (E)	Fair Value (D)	Original Cost (E)	RCND (E)	Fair Value (F)	
1	Adjusted Rate Base	Sch. B (ACC)	$ 272,013	$ 439,427	$ 355,720	$ 270,293	$ 437,706	$ 353,999	$ (1,720)	$ (1,720)	$ (1,721)	
2	Required Operating Income (a)		$ 22,108	$ 22,108	$ 22,108	$ 19,927	$ 19,927	$ 19,927	$ (2,181)	$ (2,181)	$ (2,181)	
3	Adjusted Orperating Income	Sch. C (ACC)	$ 8,045	$ 8,045	$ 8,045	$ 10,369	$ 10,369	$ 10,369	$ 2,324	$ 2,324	$ 2,324	
4	Operating Income Deficiency		$ 14,064	$ 14,064	$ 14,064	$ 9,558	$ 9,558	$ 9,558	$ (4,505)	$ (4,505)	$ (4,505)	
5	Gross Revenue Conversion Factor		1.6084	1.6084	1.6084	1.6070	1.6070	1.6070				
6	Increase in Gross Revenue Requirement		$ 22,621	$ 22,621	$ 22,621	$ 15,360	$ 15,360	$ 15,360	$ (7,261)	$ (7,261)	$ (7,261)	
7	Original DH Mullinax Testimony					$ 18,128	$ 18,128	$ 18,128				
8	Change from Original Filed Testimony					$ 2,768	$ 2,768	$ 2,768				
9	Weighted Average Cost of Captial	Schedule D	7.67%	7.67%	7.67%	7.22%	7.22%	7.22%				
10	Fair Value Adjustment		0.46%	-2.64%	-1.45%	0.15%	-2.66%	-1.59%				
11	Required Rate of Return	Schedule D	8.13%	5.03%	6.22%	7.37%	4.55%	5.63%				
12	Return on Equity		10.35%			9.50%						
	Revenue Increase and Estimated Percentage Rate Increase (Decrease)											
13	Electric Retail Revenues - Current Rates	Sch. C (ACC)	$ 147,107		$ 147,107	$ 154,888		$ 154,888	Staff Revenue from Schedule C			
14	With Proposed Base Rate Increase	Line 6 + Line 10	$ 169,728		$ 169,728	$ 170,248		$ 170,248				
15	Percent Retail Revenue Increase		15.4%		15.4%	9.9%		9.9%				

Notes and Source
Column A and B: UNSE filing, Schedule A-1

		UNSE Proposed	
[a]	Required Operating Income		
	Adjusted OCRB Rate Base	$ 272,013	
	Weighted Average Cost of Captial	7.67%	
	Required Income Before FV Adjustment	$ 20,854	$ 20,854
	Adjusted FV Rate Base	$ 355,720	
	Adjusted OCRB Rae Base	$ 272,013	
	Difference	$ 83,707	
	Return on FV Increment (b)	1.50%	
	Required Income on FV Increment	$ 1,256	$ 1,256
	Required Operating Income		$ 22,108

(b) From 2015 UNSE Rev Req Model.xlsm; Cover; Line 31

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Attachment DHM - 1

ARIZONA CORPORATION COMMISSION

UNS Electric, Inc.
Computation of Revenue Conversion Factor

Test Year Ended December 31, 2014

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Schedule A.1
Page 1 of 1

Line	Description	Company Proposed (A)	Staff Adjustment (B)	Staff Proposed (C)
1	Gross Revenue	100.00%		100.00%
2	Less: Uncollectible Revenue (a)	0.3438%	-0.0895%	0.2543%
3	Taxable Income as a Percent	99.66%		99.75%
4	State Income Tax Rate	5.48%		5.48%
5	Federal Effective Income Tax Rate [b]	32.14%		32.14%
6	Total Effective Tax Rate	37.61%		37.613%
7	Total Effective Tax Rate Adjusted for Uncollectibles	37.48%		37.52%
8	Change in Net Operating Income	62.17%		62.23%
9	Gross Revenue Conversion Factor	1.6084	(0.0014)	1.6070

Notes and Sources
Column A: UNSE filing, Schedule C-3

(a) Average Retail Expense Ratio from Bad Debt Adjustment
(b)

Federal Effective Income Tax Rate (1-State Rate*Federal Rate)	Company	Staff
1-State Income Tax Rate	94.53%	94.53%
Federal Income Tax Rate	34.0%	34.0%
Federal Effective Inocme Tax Rate	32.14%	32.14%

ARIZONA CORPORATION COMMISSION

UNS Electric, Inc.
Original Cost and RCND Adjusted Rate Base - **Modified**
ACC Jurisdictional
Test Year Ended December 31, 2014

(Thousands of Dollars)

		Original Cost			RCND		
Line	Description	As Adjusted by UNSE (A)	Staff Adjustments (B)	As Adjusted by Staff (C)	As Adjusted by UNSE (D)	Staff Adjustments (E)	As Adjusted by Staff (F)
1	Gross Utility Plant in Service	$ 664,701		$ 664,701	$ 1,169,067		$ 1,169,067
2	Less: Accumulated Depreciation	296,961	2,000	298,961	561,911	2,000	563,911
3	Net Utility Plant in Service	367,740	(2,000)	365,740	607,156	(2,000)	605,156
4	Citizens Acquisition Discount	(95,156)		(95,156)	(170,847)		(170,847)
5	Less: Accum. Amort. - Citizens Acq. Discount	(36,098)		(36,098)	(69,678)		(69,678)
6	Net Citizens Acquisition Discount	(59,058)	-	(59,058)	(101,169)	-	(101,169)
7	Total Net Utility Plant	308,682	(2,000)	306,682	505,987	(2,000)	503,987
8	Customer Advances for Construction	(3,833)		(3,833)	(4,268)		(4,268)
9	Customer Deposits	(4,428)		(4,428)	(4,428)		(4,428)
10	Other (ITC)	(422)		(422)	(422)		(422)
11	Accumulated Deferred Income Taxes	(35,161)		(35,161)	(64,617)		(64,617)
12	Total Deductions	(43,844)	-	(43,844)	(73,735)	-	(73,735)
13	Allowance for Working Capital	7,175	280	7,455	7,175	280	7,455
14	Regulatory Assets	-		-	-		-
15	Regulatory Liabilities	-		-	-		-
16	Total Rate Base	$ 272,013	$ (1,720)	$ 270,293	$ 439,427	$ (1,720)	$ 437,706

Notes and Source
Columns A and D: UNSE filing, Schedule B-1
Columns B and E: See Schedule E

Line	Fair Value Calculation (Per Company)		
17	Original Cost	$ 272,013	
18	RCND	$ 439,427	
19	Total	$ 711,440	
20	Average (Fair Value)	$ 355,720	Used in Schedule A

Line	Fair Value Calculation (Per Staff)		
21	Original Cost	$ 270,293	
22	RCND	$ 437,706	
23	Total	$ 707,999	
24	Average (Fair Value)	$ 353,999	Used in Schedule A

ARIZONA CORPORATION COMMISSION

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Schedule C
Page 1 of 1

UNS Electric, Inc.
Adjusted Net Operating Income - **Modified**
ACC Jurisdictional

Test Year Ended December 31, 2014
(Thousands of Dollars)

Line	Description	As Adjusted by UNSE (A)	Staff Adjustment (B)	As Adjusted by Staff (C)
	Operating Revenues			
1	Electric Retail Revenues	$ 147,107	$ 7,782	$ 154,888
2	Sales for Resale	(0)	-	(0)
3	Other Operating Revenues	1,828	-	1,828
4	Total Operating Revnues	$ 148,935	$ 7,782	$ 156,716
	Operating Expenses			
5	Fuel, Purchased Power, and Transmission	$ 77,522	$ 7,762	$ 85,284
6	Other Operations and Maintenance Expense	42,868	(3,718)	39,149
7	Depreciation and Amortization	13,060	-	13,060
8	Taxes Other than Inocme Taxes	6,149	(9)	6,140
9	Income Taxes	1,291	1,424	2,715
10	Total Operating Expenses	$ 140,889	$ 5,458	$ 146,348
11	Operating Income	$ 8,045	$ 2,323	$ 10,369

Notes and Sources
Column A: UNSE filing, Schedule C-1
Column B: Staff Schedule E

ARIZONA CORPORATION COMMISSION

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Schedule D
Page 1 of 1

UNS Electric, Inc.
Cost of Capital - **Modified for FVROR Calculation Error**
Test Year Ended December 31, 2014

(Thousands of Dollars)

Line	Description (A)	Reference (B)	Amount (B)	Percent (C)	Cost Rate (E)	Rate of Return (F)
	UNSE'S PROPOSED					
	UNSE Proposed Adjusted Fair Value Rate Base					
1	Original Cost Rate Base (OCRB)	Schedule B	272,013			
2	Reconstructed Cost New Depreciation (RCND)	Schedule B	439,427			
3	Fair Value Rate Base (FVRB)	Average Lines 1 & 2	355,720			
4	FVRB/OCRB Multiple	Line 3/Line 1	1.30773			
	UNSE Proposed Adjusted Captial Structure for OCRB					WACC
5	Short-Term Debt		$ -	0.00%	0.00%	0.00%
6	Long-Term Bond Debt, Net	UNSE Schedule D-1	169,590	47.17%	4.66%	2.20%
7	Common Stock Equity	UNSE Schedule D-1	189,932	52.83%	10.35%	5.47%
8	Total Capital		$ 359,522	100.00%		7.67%
	UNSE Proposed Fair Value Rate of Return					FVROR
9	Short-Term Debt		$ -	0.00%	0.00%	0.00%
10	Long-Term Bond Debt, Net	Line 1 x Line 6 (Debt %	128,311	36.07%	4.66%	1.68%
11	Common Stock Equity	Line 1 x Line 7 (Equity %)	143,702	40.40%	10.35%	4.18%
12	FVRB Increment Above Original Cost	Line 3 - Line 1	83,707	23.53%	1.50%	0.35%
13	Total Capital		$ 355,720	100.00%		6.22%
	STAFF'S RECOMMENDATION					
	Staff Proposed Adjusted Fair Value Rate Base					
14	Original Cost Rate Base (OCRB)	Schedule B	270,293			
15	Reconstructed Cost New Depreciation (RCND)	Schedule B	437,706			
16	Fair Value Rate Base (FVRB)	Average Lines 14 and 15	353,999			
17	FVRB/OCRB Multiple	Line 16/Line 14	1.30969			
	Staff Proposed Adjusted Captial Structure for OCRB					WACC
18	Short-Term Debt		$ -	0.00%	0.00%	0.00%
19	Long-Term Bond Debt, Net	UNSE Schedule D-1	169,590	47.17%	4.66%	2.20%
20	Common Stock Equity	UNSE Schedule D-1	189,932	52.83%	9.50%	5.02%
21	Total Capital		$ 359,522	100.00%		7.22%
	Staff Proposed Fair Value Rate of Return			Modified		FVROR
22	Short-Term Debt		$ -	0.00%	0.00%	0.00%
23	Long-Term Bond Debt, Net	Line 14 x Line 19 (Debt %	127,500	36.02%	4.66%	1.68%
24	Common Stock Equity	Line 14 x Line 20 (Equity	142,793	40.34%	9.50%	3.83%
25	FVRB Increment Above Original Cost	Line 14 - Line 16	83,707	23.65%	0.50%	0.12%
26	Total Capital		$ 353,999	100.00%		5.63% Modified

Notes and Sources

Line 21 and 24 Staff's recommended Cost of Common Stock Equity - see Staff Witness Elijah Abinah
Line 25 Staff's recommended FVRB ROR - see Staff Witness Elijah Abinah

ARIZONA CORPORATION COMMISSION

Docket No. E-04204A-15-0142
Schedule D.1
Page 1 of 1

UNS Electric, Inc.
Impact of Recommended **Cost of Captial** on Company's Proposed Revenue Requirements - **Modified**

(Thousands of Dollars)

Line	Description (A)	UNSE Fair Value (B)	Staff Adjustment (C)	Staff's Position (D)
1	**Adjusted Rate Base**	$ 355,720		$ 355,720
2	Weighted Average Cost of Capital	7.67%	-0.45%	7.22%
3	Fair Value Adjustment	-1.45%	-0.14%	-1.59%
4	Required Rate of Return	6.22%	-0.59%	5.63%
5	**Return Requirement**	$ 22,097	$ (2,073)	$ 20,024
6	Operating Revenues	$ 148,935		$ 148,935
7	Operating Expenses	$ 140,889		$ 140,889
8	**Net Operating Income**	$ 8,045		$ 8,045
9	**Income Deficiency**	$ 14,053		$ 11,980
10	Revenue Conversion Factor	1.6084		1.6084
11	**Revenue Deficiency**	$ 22,603	$ (3,334)	$ 19,269
12	Revenue Deficiency Percent Change		-14.75%	

ARIZONA CORPORATION COMMISSION

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Schedule E
Page 1 of 1

UNS Electric, Inc.
Summary of Rate Base and Operating Income Adjustments - **Modified**
ACC Jurisdictional
Test Year Ended December 31, 2014

Line	Description	Total Staff Adjustments	Modified E-1 Working Capital - Modified	E-2 Bad Debt Expense	Modified E-3 Injuries & Damages	Withdrawn E-4 Payroll Expense & Payroll Taxes	Modified E-5 Incentive Compensation	E-6 D&O Liability Insurance	Modified E-7 Interest Synchronizatio n	E-8 Purchased Power & Fuel	E-9 OATT	Modified E-10 Gila River Deferred Costs
		(A)	(B)	(C)	(D)	(E)	(F)	(F)	(F)	(G)	(H)	(H)
	Rate Base											
1	Gross Utility Plant in Service	$ -										
2	Less: Accumulated Depreciation	2,000,000										2,000,000
3	Net Utility Plant in Service	(2,000,000)	-	-	-	-	-	-	-	-	-	(2,000,000)
4	Citizens Acquisition Discount	-										
5	Less: Accum. Amort. - Citizens Acq. Discount	-										
6	Net Citizens Acquisition Discount	-	-	-	-	-	-	-	-	-	-	-
7	Total Net Utility Plant	$ (2,000,000)	-	-	-	-	-	-	-	-	-	(2,000,000)
8	Customer Advances for Construction	$ -										
9	Customer Deposits	-										
10	Other (ITC)	-										
11	Accumulated Deferred Income Taxes	-										
12	Total Deductions	$ -	-	-	-	-	-	-	-	-	-	-
13	Allowance for Working Capital	$ 279,710	296,489					(16,778)				
14	Regulatory Assets	-										
15	Regulatory Liabilities	-										
16	Total Rate Base	$ (1,720,290)	$ 296,489	$ -	$ -	$ -	$ -	$ (16,778)	$ -	$ -	$ -	$ (2,000,000)
	Operating Revenues											
17	Electric Retail Revenues	$ 7,781,533								$ 7,781,533		
18	Sales for Resale	-										
19	Other Operating Revenues	-										
20	Total Operating Revenues	$ 7,781,533	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,781,533	$ -	$ -
	Operating Expenses											
21	Fuel, Purchased Power, and Transmission	$ 7,761,608								$ 7,781,533	$ (19,925)	
22	Other Operations and Maintenance Expens	(3,718,384)		(131,640)	(320,100)		(146,616)	(20,028)				(3,100,000)
23	Depreciation and Amortization	-										
24	Taxes Other than Income Taxes	(8,738)					(8,738)					
25	Income Taxes	1,423,625		49,514	120,401		58,435	7,533	14,229		7,494	1,166,019
26	Total Operating Expenses	$ 5,458,111	$ -	$ (82,126)	$ (199,699)	$ -	$ (96,920)	$ (12,495)	$ 14,229	$ 7,781,533	$ (12,431)	$ (1,933,981)
27	Operating Income	$ 2,323,422	$ -	$ 82,126	$ 199,699	$ -	$ 96,920	$ 12,495	$ (14,229)	$ -	$ 12,431	$ 1,933,981

Notes and Sources

ARIZONA CORPORATION COMMISSION

UNS Electric, Inc.
Cash Working Capital - **Modified**

Test Year Ended December 31, 2014

(Thousands of Dollars)

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	Cash Working Capital	$ (5,197,996)	$ 296,489	$ (4,901,507)
2	**Impact to Rate Base**	$ (5,197,996)	$ 296,489	$ (4,901,507)

Notes and Sources

See CWC Workpaper

ARIZONA CORPORATION COMMISSION

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Schedule E-1 WP
Page 1 of 1

UNS Electric, Inc.
Cash Working Capital Workpaper - **Modified**

Test Year Ended December 31, 2014

(Thousands of Dollars)

		UNSE Proposed						Staff Recommendation	
Line	Description	Pro Forma Test Year Amount	Revenue Lag Days	Expense Lag Days	Net Lag Days (C - D)	Lead/Lag Factor (E/365)	Cash Working Capital (F x B)	Adjustments	Cash Working Capital
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Operating Expenses								
	Non-Cash Expenses								
1	Bad Debts Expense	$ 506						$ (132)	
2	Depreciation	11,406							
3	Amortization	(3,629)							
4	Deferred Income Taxes	4,627							
	Other Operating Expenses								
5	Salaries and Wages (UNSE Direct Employees)	4,616	35.59	23.33	12.26	0.0336	$ 155	-	-
6	Incentive Pay (UNSE Direct Employees)	329	35.59	267.00	(231.41)	(0.6340)	(209)	(147)	93
7	Purchased Power	62,965	35.59	33.79	1.80	0.0049	311	7,782	38
8	Transmission Other	9,014	35.59	40.67	(5.08)	(0.0139)	(125)	(20)	0
9	Meter Reading	574	35.59	33.67	1.92	0.0053	3		-
10	Customer Records & Collection Expenses (excluding allocati	1,169	35.59	34.94	0.65	0.0018	2		-
11	Office Supplies and Expenses	1,005	35.59	50.89	(15.30)	(0.0419)	(42)		-
12	Injuries and Damages	750	35.59	70.52	(34.93)	(0.0957)	(72)	(340)	33
13	Pensions and Benefits	1,960	35.59	51.37	(15.78)	(0.0432)	(85)		-
14	Support Services - TEP (Direct Labor, Burdens, System Alloc	6,059	35.59	44.77	(9.18)	(0.0252)	(152)		-
15	Property Taxes	6,733	35.59	212.00	(176.41)	(0.4833)	(3,254)		-
16	Payroll Taxes	376	35.59	12.00	23.59	0.0646	24	(9)	(1)
17	Current Income Taxes	-	35.59	0.00	35.59	0.0975	-	$\boxed{1,424}$	139
18	Interest on Customer Deposits	7	35.59	182.50	(146.91)	(0.4025)	(3)		-
19	Other Operations and Maintenance	25,050	35.59	41.21	(5.62)	(0.0154)	(386)		-
20	Total Operating Expenses	133,517				-		$ 8,558	
	Other Cash Working Capital Elements:								
21	Interest On Long-Term Debt	7,859	35.59	89.50	(53.91)	(0.1477)	(1,161)		
22	Revenue Taxes and Assessments	11,717	35.59	49.43	(13.84)	(0.0379)	(444)		
23	Total Cash Working Capital					Total Company	$ (5,438)		$ 302
24						ACC Jurisdiction Ratio	96%		96%
25						ACC Jurisdiction	(5,198)		$ 296
		w/o Int Synch	w/ Int Synch	Int Synch					
26.00	Current Income Taxe	1,409	$\boxed{1,424}$	14					

Notes and Sources

Lead/Lag Study from UNSE Schedule B-5, page 3 of 3

Line 24 - ACC Jurisdiction Ratio - 2015 UNSE Rev Req Model, Tab Rate Base, Cell AD 279

ARIZONA CORPORATION COMMISSION

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Schedule E-2
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UNS Electric, Inc.
Bad Debt Expense

Test Year Ended December 31, 2014

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	Adjusted Retail Revenue	##########		##########
2	Three-Year Average Retail Expense Ratio	0.34375%		0.25426%
3	Pro Forma Bad Debt Expense	505,677		374,037
4	Recorded Test Year Bad Debt Expense	863,828		863,828
5	Adjust Recorded to Normalized Bad Debt	$ (358,151)	$ (131,640)	$ (489,791)
6	State Income Tax Rate	5.475%		5.475%
7	Effect on State income tax expense	$ 19,609	$ 7,207	$ 26,816
8	Federal Taxable	$ (338,542)		$ (462,975)
9	Federal Income Tax Rate	34.00%		34.00%
10	Effect on Federal income tax expense	$ 115,104	$ 42,307	$ 157,411
11	Total Income Tax		$ 49,514	
12	Total Expense	$ (223,438)	$ (82,126)	$ (305,564)
13	**Impact to Operating Income**	$ 223,438	$ 82,126	$ 305,564

Notes and Sources

Line 1 - UNSE response to UDR 1.001 Income-Bad Debt Expense

UNSE response to UDR 1.001 Income-Bad Debt Expense

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
	Unadjusted Retail Revenue			
14	2012	##########		##########
15	2013	160,650,785		160,650,785
16	2014	167,998,569		167,998,569
	Bad Debt Expense			
17	2012	$ 518,681		$ 518,681
18	2013	310,216		310,216
19	2014	863,828	$ (450,000)	413,828
				$ 1,242,724
	% Retail Expense to Retail Revenue			
20	2012	0.32396%		0.32396%
21	2013	0.19310%		0.19310%
22	2014	0.51419%		0.24633%
23	Average of Average Retail Expense Ratio	0.34375%		0.25446%
24	Total Unadjusted Retail Revenue	##########		##########
25	Total Bad Debt Expense	$ 1,692,724		$ 1,242,724
26	Three-Year Average Retail Expense Ratio	0.34633%		0.25426%
27	Uncollected Revenues Ratio - Schedule A.1	0.34375%		0.25426%

State and Federal Income Tax Rate - UNSE response to UDR 1.068

ARIZONA CORPORATION COMMISSION

Docket No. E-04204A-15-0142
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UNS Electric, Inc.
Injuries and Damages - **Modified for ACC Jurisdictional Allocation**

Test Year Ended December 31, 2014

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	FERC 925 Injuries and Damages			
2	Year Ended 2012	$ 32,670		$ 32,670
3	Year Ended 2013	1,133,687	$ (1,000,000)	133,687
4	Year Ended 2014	27,797		27,797
5	Total Company FERC 925 Injuries and Damages	1,194,153		194,153
6	ACC Jurisdictional Allocation	96.03%		96.03%
7	Total ACC Jurisdiction FERC 925 Injuries and Damage	1,146,745		186,445
8	Three-Year Average	$ 382,248	$ (320,100)	$ 62,148
9	State Income Tax Rate	5.475%		5.475%
10	Effect on State income tax expense	$ (20,928)	$ 17,525	$ (3,403)
11	Federal Taxable	$ 361,320		$ 58,745
12	Federal Income Tax Rate	34%		34%
13	Effect on Federal income tax expense	$ (122,849)	$ 102,876	$ (19,973)
14	Total Income Tax		$ 120,401	
15	Total Expense	$ 238,471	$ (199,699)	$ 38,772
16	**Impact to Operating Income**	$ (238,471)	$ 199,699	$ (38,772)

Notes and Sources

Lines 2-4 - UNSE response to UDR 1.001 Income-Injuries & Damages

State and Federal Income Tax Rate - UNSE response to UDR 1.068

ARIZONA CORPORATION COMMISSION

UNS Electric, Inc.
Payroll Expense and Payroll Taxes - **Withdrawn**

Test Year Ended December 31, 2014

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
	Adjustment withdrawn.			

Notes and Sources

Lines 2-11 Column A - UNSE response to UDR 1.001 Income - Payroll Expense
Line 2-3 Column B - UNSE response to UDR STF 6.12

Line 13 UNSE response to UDR 1.001 Income-Payroll Tax Expense - Effective Tax Rate = 7.8%

State and Federal Income Tax Rate - UNSE response to UDR 1.068

ARIZONA CORPORATION COMMISSION

UNS Electric, Inc.
Incentive Compensation - **Modified for ACC Jurisdictional Allocation**

Test Year Ended December 31, 2014

Line	Description	ACC Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	Incentive Compensation	$ 302,790	$ (146,616)	$ 156,173
2	Payroll Taxes	$ 13,293	$ (8,738)	$ 4,554
3	Total Payroll Expense and Payroll Taxes	$ 316,082		$ 160,728
4	State Income Tax Rate	5.475%		5.475%
5	Effect on State income tax expense	$ (17,306)		$ (8,800)
6	Federal Taxable	$ 298,776		$ 151,928
7	Federal Income Tax Rate	34%		34%
8	Effect on Federal income tax expense	$ (101,584)		$ (51,655)
9	Total Income Tax	$ (118,890)	$ 58,435	$ (60,455)
10	Total Expense	$ 197,192	$ (96,920)	$ 100,273
11	**Impact to Operating Income**	$ (197,192)	$ 96,920	$ (100,273)

Notes and Sources

See Workpaper

ARIZONA CORPORATION COMMISSION

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UNS Electric, Inc.
Incentive Compensation Workpaper - **Modified for ACC Jurisdictional Allocation**

Test Year Ended December 31, 2014

Line	Description	2012 (A)	2013 (B)	2014 (C)	Average (D)	Pay Increase (E)	Total Company (F)	ACC Jurisdictional Allocation (G)	Total ACC (H)
	As Filed by UNSE								
1	Incentive Compensation by FERC Account								
2	0581	$ -	$ 10,996	$ 11,556	$ 7,518	$ 595	$ 8,113	100%	$ 8,113
3	0583	12,226	36	-	4,088	324	4,412	100%	4,412
4	0592	11,774	32	-	3,935	311	4,247	100%	4,247
5	0593	10,754	7,952	7,154	8,620	682	9,302	100%	9,302
6	0901	16,458	20,650	25,967	21,025	1,664	22,689	100%	22,689
7	0908	(1,090)	8,238	11,652	6,267	496	6,763	100%	6,763
8	0920	221,542	241,707	252,559	238,603	18,884	257,487	96.03%	247,264
9	O&M	$ 271,666	$ 289,610	$ 308,890	$ 290,056	$ 22,956	$ 313,012		$ 302,790
10	Non-Taxable	(118,215)	(130,669)	(131,471)					
11	Taxable	153,451	158,942	177,419					
12	Effective Payroll Tax Rate	7.8%	7.8%	7.8%				Prorated	
13		$ 11,969	$ 12,397	$ 13,839	$ 12,735	$ 1,006	$ 13,741	96.73%	$ 13,293
14	Total	$ 165,420	$ 171,339	$ 191,258	$ 302,791	$ 23,963	$ 326,753		$ 316,082
	Pay Increase - 2%								
15	2012								
16	2013	$ 5,433							
17	2014	5,433	$ 5,792						
18	2014	5,433	5,792	$ 6,178					
19	2016	5,433	5,792	6,178					
20	2017	5,433	5,792	6,178					
21	Total	$ 27,167	$ 23,169	$ 18,533	$ 22,956				
	Payroll Taxes - 2% Increase								
22	2012								
23	2013	$ 239							
24	2014	239	$ 248						
25	2014	239	248	$ 277					
26	2016	239	248	277					
27	2017	239	248	277					
28	Total	$ 1,197	$ 992	$ 830	$ 1,006				

Line	Description	2012 (A)	2013 (B)	2014 (C)	Average (D)	Pay Increase (E)	Total (F)	50/50 Sharing (G)	ACC Jurisdiction al Allocation (H)	Total ACC (I)
	Staff's Adjustment									
29	Incentive Compensation by FERC Account									
30	0581		$ 10,996	$ 11,558	$ 11,277	$ 893	$ 12,170	$ 6,085	100%	$ 6,085
31	0583		36	-	18	1	19	10	100%	10
32	0592		32	-	16	1	17	9	100%	9
33	0593		7,952	7,154	7,553	598	8,151	4,075	100%	4,075
34	0901		20,650	25,967	23,308	1,845	25,153	12,576	100%	12,576
35	0908		8,238	11,652	9,945	787	10,732	5,366	100%	5,366
36	0920		241,707	252,559	247,133	19,559	266,692	133,346	96.03%	128,052
37	O&M	$ -	$ 289,610	$ 308,890	$ 299,250	$ 23,684	$ 322,934	$ 161,467		######
38	Non-Taxable		(130,669)	(131,471)						
39	Taxable	-	158,942	177,419						
40	Effective Payroll Tax Rate	7.8%	7.8%	7.8%					Prorated	
41		$ -	$ 12,397	$ 13,839	$ 8,745	$ 672	$ 9,417	$ 4,709	96.72%	$ 4,554
42	Total	$ -	$ 171,339	$ 191,258	$ 307,996	$ 24,356	$ 332,352	$ 166,176		######
	Pay Increase - 2%									
43	2012									
44	2013	$ -								
45	2014	5,433	$ 5,792							
46	2015	5,433	5,792	$ 6,178						
47	2016	5,433	5,792	6,178						
48	2017									
49	Total	$ 16,300	$ 17,377	$ 12,356	$ 15,344					
	Payroll Taxes - 2% Increase									
50	2012									
51	2013	$ -								
52	2014	239	$ 248							
53	2015	239	248	$ 277						
54	2016	239	248	277						
55	2017									
56	Total	$ 718	$ 744	$ 564	$ 672					

Notes and Sources

Lines 1-28 UNSE response to UDR 1.001 Income-Incentive Compensation

ARIZONA CORPORATION COMMISSION

UNS Electric, Inc.
Directors and Officers (D&O) Liability Insurance

Test Year Ended December 31, 2014

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Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	FERC 165 D&O Liability Insurance Prepaid	$ 33,557	$ (16,778)	$ 16,778
2	**Impact to Rate Base**	$ 33,557	$ (16,778)	$ 16,778
3	FERC 925 Officers & Directors Liability	$ 145,954		
4	Amount excluded by UNSE in Fortis	(105,899)		
5	D&O Liability Insurance in Test Year	40,055	$ (20,028)	20,028
6	State Income Tax Rate	5.475%		5.475%
7	Effect on State income tax expense	$ (2,193)	$ 1,096	$ (1,097)
8	Federal Taxable	$ 37,862		$ 18,931
9	Federal Income Tax Rate	34%		34%
10	Effect on Federal income tax expense	$ (12,873)	$ 6,437	$ (6,436)
11	Total Income Tax		$ 7,533	
12	Total Expense	$ 24,989	$ (12,495)	$ 12,495
13	**Impact to Operating Income**	$ (24,989)	$ 12,495	$ (12,495)

Notes and Sources

Line 1 - UNSE response to STF 10.14
Line 3 - UNSE supplemental response to UDR 1.59
Line 4 - UNSE response to STF 16.05

State Income Tax Rate - UNSE response to RUCO 1.03

ARIZONA CORPORATION COMMISSION

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UNS Electric, Inc.
Interest Synchronization - **Modified Due Change in Working Capital - Rate Base**

Test Year Ended December 31, 2014

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	Rate Base	$ 272,013,000	$ (1,720,290)	$ 270,292,710
2	Interest Component of Rate of Return	2.20%		2.20%
3	Interest Attributable to Rate Base	5,981,248	(37,827)	5,943,421
4	State Income Tax Rate	5.475%		5.475%
5	Effect on State income tax expense	$ (327,473)	$ 2,071	$ (325,402)
6	Federal Taxable	$ 5,653,775		$ 5,618,019
7	Federal Income Tax Rate	34%		34%
8	Effect on Federal income tax expense	$ (1,922,284)	$ 12,158	$ (1,910,126)
9	Total Income Tax		$ 14,229	
10	Total Expense	$ (2,249,757)	$ 14,229	$ (2,235,528)
11	**Impact to Operating Income**	$ 2,249,757	$ (14,229)	$ 2,235,528

Notes and Sources

Line 1 Original Cost Rate Base from Schedule B
Line 2 Interest Component of Rate of Return - OCRB Weighted Cost of Long Term Debt on Schedule D

ARIZONA CORPORATION COMMISSION

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UNS Electric, Inc.
Purchased Power and Fuel Adjustment Clause (PPFAC)

Test Year Ended December 31, 2014

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	Test Year Adjusted Billing Detemrinants (kWh)	1,600,809,167		1,600,809,167
2	Proposed Base Cost Rate ($ per kWh)	0.048427	0.004861	0.053288
3	Base Cost of Fuel and Purchased Power	$ 77,522,386	$ 7,781,533	$ 85,303,919
4	**Electric Retail Revenues**		$ 7,781,533	
5	**Expense: Fuel, Purchased Power and Transmission**		$ 7,781,533	
6	**Impact to Operating Income**		$ -	

Notes and Sources

See Direct Testimony of Barbara Keene

State Income Tax Rate - UNSE response to RUCO 1.03

ARIZONA CORPORATION COMMISSION

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UNS Electric, Inc.
OATT

Test Year Ended December 31, 2014

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	OATT	14,531,456	$ (19,925)	14,511,531
2	State Income Tax Rate	5.475%		5.475%
3	Effect on State income tax expense	$ (795,597)	$ 1,091	$ (794,506)
4		$ 13,735,859		$ 13,717,025
5	Federal Income Tax Rate	34%		34%
6	Effect on Federal income tax expense	$ (4,670,192)	$ 6,403	$ (4,663,789)
7	Total Income Tax		$ 7,494	
8	Total Expense	$ 9,065,667	$ (12,431)	$ 9,053,236
9	**Impact to Operating Income**	$ (9,065,667)	$ 12,431	$ (9,053,236)

Notes and Sources

See Direct Testimony of Eric Van Epps

State Income Tax Rate - UNSE response to RUCO 1.03

ARIZONA CORPORATION COMMISSION

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UNS Electric, Inc.
Gila River Deferred Cost - **Modified**

Test Year Ended December 31, 2014

(Thousands of Dollars)

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
	Accumlated Depreciation - Gila River			
1	Accumulated Depreciation	$ -	$ 2,000,000	$ 2,000,000
2	**Impact to Rate Base**	$ -	$ (2,000,000)	$ (2,000,000)
3	Regulatory Asset Amoritzation - Gila River Savings			
4	Other Operations and Maintence Expense	$ 3,100,000	$ (3,100,000)	$ -
5	State Income Tax Rate	5.475%		5.475%
6	Effect on State income tax expense	$ (169,725)	$ 169,725	$ -
7	Federal Taxable	$ 2,930,275		$ -
8	Federal Income Tax Rate	34%		34%
9	Effect on Federal income tax expense	$ (996,294)	$ 996,294	$ -
10	Total Income Tax		$ 1,166,019	
11	Total Expense	$ 1,933,981	$ (1,933,981)	$ -
12	**Impact to Operating Income**	$ (1,933,981)	$ 1,933,981	$ -

Notes and Sources

See Direct Testimony of Barbara Keene for Accumulated Depreciation
See Surrebuttal Testimony of Barbara Kenne for Regulatory Asset Amortization
Line 4 - UNSE response to UDR 1.001 Income-Gila River Deferred Cost

UNS ELECTRIC, INC.
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED DECEMBER 31, 2014

ADJUSTMENT NAME:	Gila River Deferred Cost
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	April 15, 2015
PREPARED BY:	Mike Sheehan
CHECKED BY:	David Lewis
REVIEWED BY:	

		Total Company		ACC Jurisdictional	
FERC ACCT	**FERC ACCOUNT DESCRIPTION**	**DEBIT**	**CREDIT**	**DEBIT**	**CREDIT**
407.1	Regulatory Asset Amortization	$3,100,000		$3,100,000	
	ENTRY TOTAL	**$3,100,000**	**$0**	**$3,100,000**	**$0**
	NET ENTRY	**$3,100,000.00**		**$3,100,000.00**	

Reason for Adjustment

To adjust for cost allowable for recovery per ACC Deferred Accounting Order. Decision No. 74911

UNS Electric, Inc.
Gila River Unit 3

In Decision No. 74911 dated January 22, 2015, the ACC approved UNS Electric's request to defer for future recovery non-fuel costs including: (i) depreciation and amortization costs, (ii) property taxes, (iii) O&M expenses, and (iv) carrying costs calculated at 5% associated with owning, operating, and maintaining the plant for the period January 1, 2015 through the earlier of April 30, 2016 or the date new rates go into effect. The maximum amount of costs subject to deferral is the lesser of $10.5 million or the cumulative deferred savings as of April 30, 2016. The deferred savings will continue to accrue until new rates go into effect. UNS Electric will file monthly reports with Docket Control detailing the calculations related to allowable costs and savings. UNS Electric expects non-fuels costs to approximate $9 million by the end of 2015.

Mike Estimates the total to by 9.1M

EXHIBIT
S-3
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

SUSAN BITTER SMITH
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
DOUG LITTLE
Commissioner
TOM FORESE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. 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 UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

DIRECT

TESTIMONY

OF

ELIJAH ABINAH

ASSISTANT DIRECTOR

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 6, 2015

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EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-15-0142

This testimony will address cost of equity, fair value increment and capital structure for UNS Electric, Inc. ("UNSE" or "Company").

Staff recommends that the Commission grant UNSE a 9.5 percent cost of equity, 0.50 percent fair value increment. This is the same cost of equity and fair value increment awarded to UNSE in Commission Decision No. 74235.

Staff further recommends that the Commission approve the capital structure as proposed by the Company without any modifications/changes.

INTRODUCTION

Q. Please state your name, and business address.

A. My name is Elijah Abinah. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Where are you employed and in what capacity?

A. I am employed by the Arizona Corporation Commission ("ACC" or "Commission") of the Utilities Division ("Staff") as Assistant Director.

Q. How long have you been employed with the Utilities Division?

A. I have been employed with the Utilities Division since January 2003.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science degree in Accounting from the University of Central Oklahoma in Edmond, Oklahoma. I also received a Master of Management degree from Southern Nazarene University in Bethany, Oklahoma. Prior to my employment with the ACC, I was employed by the Oklahoma Corporation Commission for approximately eight and a half years in various capacities in the Telecommunications Division.

Q. What are your current responsibilities?

A. As Assistant Director, I review submissions that are filed with the Commission and make policy recommendations to the Director regarding those filings.

Q. Have you previously submitted testimony before the Commission?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide Staff's recommendations on the subject of cost of capital.

Q. What is Staff's recommendation?

A. Staff recommends that the Commission grant UNS Electric, Inc. ("UNSE" or "Company") a 9.5 percent cost of equity and 0.50 percent fair value increment. This is the same cost of equity and fair value increment awarded to UNSE in Commission Decision No. 74235, issued on December 31, 2013.

COST OF CAPITAL

Q. Did you perform any Cost of Capital analysis in this case?

A. No.

Q. Are you presenting yourself as an expert witness on the subject of cost of capital?

A. No. I intend to present Staff's rationale for utilizing the same cost of capital that was approved in UNSE's last rate case in Decision No. 74235.

Q. What is the basis for your recommendation?

A. Staff relies on prior Commission decisions in making its recommendation.

Q. Are you stating that prior Commission decisions are precedential or set a precedent?

A. No. Staff has always maintained that each case stands on its own merit. However, Staff also believes that prior Commission decisions can be relied on when making recommendations, and nothing precludes Staff from relying on prior Commission decisions when doing so.

Q. Can you please explain Staff's rationale for recommending the cost of capital awarded the Company in its last rate case?

A. Staff recognizes that cost of capital is an opportunity cost and prospective looking. However, based on prior experience, relying a prior Commission decision gives Staff comfort because it is relevant, reasonable and consistent. For instance, in Docket No. E-04204A-09-0206, Staff retained David C. Parcell to evaluate the cost of capital aspect of UNSE's rate case filing. In that proceeding, Mr. Parcell developed the appropriate capital structure for UNSE. He then performed a cost of capital calculation to determine the embedded cost of debt and then calculated the estimated cost of common equity. In estimating the cost of common equity, Mr. Parcell employed three recognized methodologies and applied them to two groups of proxy utilities. Consistent with Mr. Parcell's testimony, the three methodologies resulted in a cost of capital for UNSE that ranged from 7.6 percent to 10.5 percent.

Methodology	Range
Discounted Cash flow	9.4% – 10.1%
Capital Asset Pricing Model	7.6% - 8.3%
Comparable Earning	9.5% - 10.5%

Based on those findings, Mr. Parcell concluded that the cost of common equity for UNSE was within the range of 9.5 percent to 10.5 percent. Mr. Parcell further recommended a 10 percent cost of equity for UNSE. According to Mr. Parcell, 10 percent was the midpoint. In addition, Mr. Parcell maintained that 10 percent was the cost of capital the Commission approved for UNSE in its prior rate case.

Q. Did the Commission approve the methodologies and the cost of equity recommended by Mr. Parcell?

A. The Commission approved the methodologies; however, the Commission decided to award UNSE a lower cost of equity that was within the range produced by Mr. Parcell's analysis.

Q. As it related to the Company's capital structure and cost of debt, did Mr. Parcell make any adjustments?

A. No. Mr. Parcell, based on his analyses, went along with the Company's proposed capital structure and cost of debt.

Q. Did the Commission find those recommendations to be just, fair and reasonable to the Company, ratepayers and stakeholders?

A. Yes. In addition, Staff again retained Mr. Parcell to evaluate the cost of capital aspect of UNSE's rate case filing in Docket No. E-04204A-12-0504. In that proceeding, Mr. Parcell developed the appropriate capital structure for UNSE. He then performed a cost of capital calculation to determine the embedded cost of debt and then calculated the estimated cost of common equity. In estimating the cost of common equity, Mr. Parcell again employed three recognized methodologies and applied them to two groups of proxy utilities. Consistent with Mr. Parcell's testimony, the three methodologies resulted in a cost of capital for UNSE that ranged from 8.5 percent to 10 percent.

Methodology	Range
Discounted Cash flow	8.5% – 10%
Capital Asset Pricing Model	6.5% - 6.8%
Comparable Earning	9.0% - 9.5%

Based on those findings, Mr. Parcell concluded that the cost of common equity for UNSE should be within the range of 8.5 percent to 10. percent. Mr. Parcell further recommended a 9.25 percent cost of equity for UNSE.

Q. Did the Commission approve the methodologies and the cost of equity recommended by Mr. Parcell?

A. The Commission approved the methodologies; however, the Commission decided to award UNSE a lower cost of equity that was within the range produced by Mr. Parcell's analysis.

Q. Did Mr. Parcell make any adjustments to the Company's proposed capital structure and cost of debt in Docket No. E-04204A-12-0504?

A. No. Mr. Parcell, based on his analysis, went along with the Company's proposed capital structure and cost of debt.

Q. Did the Commission find those recommendations to be just, fair and reasonable to the Company, ratepayers and stakeholders?

A. Yes.

Q. In addition to the independent studies performed by Mr. Parcell in Docket No. E-04204A-12-0504, what was the outcome of that docket?

A. The Company, Staff and the Residential Utility Consumer Office ("RUCO") reached a settlement agreement. The settlement agreement provides for a 9.5 percent cost of equity which was within the range that the witnesses for the Company, Staff and RUCO each produced based on their analyses and various methodologies.

Q. Did the Commission approve the settlement agreement?

A. Yes. The Commission found that the agreement reached by the parties was just, fair and reasonable and was adopted in Decision No. 74235.

Q. Based on that, does Staff believe the 9.5 percent cost of equity it recommends in this case is just, fair and reasonable to all parties involved?

A. Yes.

Q. Based on your review of Mr. Parcell's testimony in prior dockets, does Staff believe that a cost of capital analysis performed in the instant case would produce a widely different result?

A. No. Staff believes that a cost of capital analysis in the docket would produce a similar, if not identical, range of 8.5 percent to 10.5 percent regardless of the methodologies employed by the various parties.

Q. What are the other reasons for recommending the cost of equity that was approved in the Company's last rate case?

A. Staff timely secured external expert witnesses for many of the work elements identified in this rate filing through a Request for Proposal ("RFP") process including Rate Base, Revenue Requirement, Cost of Service, Rate Design, and Engineering. Remaining work elements such as Cost of Capital, Rules & Regulations, and Power Supply were assigned internally to Staff. Ultimately, Staff did not conduct a cost of capital analysis, choosing, instead, to rely on the analysis of David Parcell and prior Commission Decisions.

Q. Have you had the opportunity to review the Company's testimony on the subject of cost of capital?

A. Yes.

Q. Can you please briefly describe the Company's proposals?

A. Yes. For the test year, the Company is proposing the following:

- Long Term Debt: 47.17 percent
- Common Equity: 52.83 percent
- Cost of Equity: 10.35 percent
- Cost of Debt: 4.66 percent
- Fair Value Rate of Return: 6.22 percent
- Fair Value Increment: 1.50 percent

Q. Which Decisions are you referencing?

A. In making its recommendations, Staff relies on prior Commission Decision Nos. 71914 and 74235.

Q. What was the capital structure proposed by the Company in Docket No. E-04204A-09-0206?

A. The Company proposed a capital structure of 54.24 percent long term debt and 45.76 percent common equity.

Q. What was the cost of common equity and cost of debt proposed by the Company in Docket No. E-04204A-09-0206?

A. The Company proposed 11.4 percent cost of equity and 7.05 percent cost of debt.

Q. In Docket No. E-04204A-09-0206, what was Staff's recommendation as it related to the cost of common equity, cost of debt and capital structure for UNSE?

A. Staff recommended a 10 percent cost of equity, 7.05 percent cost of debt, 54.24 capital structure percent long term debt and 45.76 percent capital structure.

Q. What was RUCO'S recommendation?

A. In Docket No. E-04240A-09-0206, RUCO recommended a cost of common equity of 9.25 percent, 7.05 percent cost of debt and a capital structure of 54.24 percent long term debt and 45.76 percent common equity.

Q. In making your recommendation, is Staff relying on any other prior Commission Decisions?

A. Yes. Staff is also relying on Commissions Decision No. 74235 in making its recommendation.

Q. What was the capital structure proposed by the Company in Docket No. E-04204A-12-0504?

A. The Company proposed a capital structure of 47.40 percent long term debt and 52.60 percent common equity.

Q. What was the cost of common equity and cost of debt proposed by the Company in Docket No. E-04204A-12-0504?

A. The Company proposed 10.5 percent cost of equity and 5.97 percent cost of debt.

Q. In Docket No. E-04204A-12-0504, what was Staff's recommendation as it related to the cost of common equity, cost of debt, and capital structure for UNSE?

A. Staff recommended a 9.25 percent cost of equity, 5.97 percent cost of debt and a capital structure of 47.40 percent long term debt and 52.60 percent common equity.

Q. What was RUCO'S recommendation?

A. In Docket No. E-04240A-12-0504, RUCO recommended a cost of equity of 8.16 percent, 5.99 percent cost of debt and a capital structure of 47.40 percent long term debt and 52.60 percent common equity.

Q. Have you had the opportunity to review the capital structure that was approved by the Commission in Decision Nos. 71914 and 74235?

A. Yes. The Commission approved the Company's proposed capital structures without any modifications or changes.

Q. Have you had the opportunity to review the cost of debt approved by the Commission in Decision Nos. 71914 and 74235?

A. Yes. In Decision Nos. 71914 and 74235, the Commission awarded UNSE cost of debt of 7.05 percent and 5.97 percent, respectively.

Q. Based on the above, is it appropriate for the Commission to approve the Company's proposed capital structure and cost of debt in this rate case?

A. Yes. As stated above, the Commission adopted the capital structure and cost of debt proposed by the Company in Docket Nos. E-04204A-09-0206 and E-04204A-12-0504 without any changes or modifications. Staff believes it is appropriate and in the public interest to adopt the Company's proposed capital structure and the cost of debt in the instant case.

Q. Have you had the opportunity to review the cost of equity approved by the Commission in Decision Nos. 71914 and 74235?

A: Yes. In Decision Nos. 71914 and 74235, the Commission awarded UNSE cost of equity of 9.75 percent and 9.50 percent, respectively.

Q. Does Staff believe the proposed 9.50 percent will accord the Company the opportunity to earn a reasonable rate of return?

A: Yes. As noted on page 34, lines 6 through line 9, in Commission Decision No 71914, "[t]here is no mathematical, mechanical, or precise procedure or formula for determining a company's cost of capital. Because the cost of capital is an opportunity cost and is prospective-looking, it can only be estimated. Experts rely on various analyses to reach recommendations and those recommendations reflects their use of assumptions and forecasts."

Based on the above statement, Staff believes estimating the cost of capital at 9.50 percent will accord the company the opportunity to earn a reasonable return on its investment because it is consistent with the public interest.

FAIR VALUE RATE OF RETURN AND FAIR VALUE INCREMENT

Q. In Docket E-04204A-09-0206, what was the fair value rate of return ("FVROR") proposed by the Company, Staff and RUCO?

A. The Company proposed 6.88 percent, Staff proposed 6.01 percent and RUCO proposed 5.95 percent.

Q. In Decision No. 71914, what was the FVROR adopted by the Commission?

A. The Commission adopted a FVROR of 6.18 percent.

Q. What was the fair value increment approved by the Commission in Decision No. 71914 for UNSE?

A. The Commission adopted a 2.1 percent fair value increment for UNSE.

Q. In Decision No. 74235, what was the fair value increment that was approved by the Commission for UNSE?

A. The Commission approved a 0.50 percent fair value increment.

Q. Based on that, is it appropriate for the Commission to approve a similar fair value increment in this rate case?

A. Yes.

Q. Does Staff have any reason to disagree with the Company's proposed capital structure, cost of debt, cost of equity, and fair value increment?

A. No.

Q. Does Staff believe it is in the public interest for the Commission to adopt the proposed capital structure and cost of debt proposed by the Company?

A. Yes.

Q. Is Staff recommending that the Commission adopt the cost of equity, and fair value increment as proposed by the Company?

A. No. Staff believes the Commission should adopt and award the same cost of equity, and fair value increment that was awarded the Company in Decision No. 74235 because Staff believes it is relevant, reasonable, and consistent.

Q. What are Staff's recommendations in this instant case?

A. Staff is recommending the following:

Long Term Debt	47.15%
Common Equity	52.83%
Cost of Debt	4.66%
Cost of Common Equity	9.5%
FVROR Increment	0.50%

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

EXHIBIT
S-4
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

Commissioners
Susan Bitter Smith – Chairman
Bob Stump
Bob Burns
Doug Little
Tom Forese

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. 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 UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

DIRECT

TESTIMONY

OF

HOWARD SOLGANICK

ON BEHALF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 6, 2015

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EXHIBIT

EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-15-0142

Mr. Solganick's direct testimony summarizes the review performed by Blue Ridge Consulting Services, Inc. ("Blue Ridge") of the UNS Electric, Inc. ("UNSE" or "Company") electric system planning, quality, maintenance practices, and distribution system reliability indices. Blue Ridge also reviewed the "used and usefulness" of assets included in the proposed rate base which were subject to field inspections. Blue Ridge also reviewed the Company's peak demand, system energy, numbers and types of customers and system losses.

Blue Ridge's review was performed using a spectrum of techniques including data requests, interviews, and field visits. This review process is similar to a management or operational audit. After the analysis of the information provided or developed, Blue Ridge has concluded that the Company's processes and procedures covering the planning process and various operational areas are reasonable. Blue Ridge's recommendations for improvement include:

- Blue Ridge recommends that the Company perform a loss study covering various levels, such as transformation and line losses, which would require engineering input.
- Blue Ridge recommends the Company coordinate its loss factors for load research with an engineering-based loss study.

QUALIFICATIONS

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

A. My name is Howard Solganick. I am a Principal at Energy Tactics & Services, Inc. My business address is 810 Persimmon Lane, Langhorne, Pennsylvania 19047. I am performing this assignment under subcontract to Blue Ridge Consulting Services, Inc. ("Blue Ridge") on behalf of the Arizona Corporation Commission ("Commission") Utilities Division's Staff ("Staff").

Q. Please summarize your qualifications and experience.

A. I am licensed as a Professional Engineer in Pennsylvania (active) and New Jersey (inactive). I hold a Professional Planner's license (inactive) in New Jersey. I served on the Electric Power Research Institute's Planning Methods Committee and on the Edison Electric Institute Rate Research Committee. I have been appointed as an arbitrator in cases involving a pricing dispute between a municipal entity and an on-site power supplier and a commercial landlord-tenant case concerning sub-metering and billing. I previously served on two New Jersey Zoning Boards of Adjustment as Chairman and member and a Pennsylvania Township Planning Commission as Chairman and member.

I have been actively engaged in the utility industry for over 40 years, holding utility management positions in generation, rates, planning, operational auditing, facilities permitting, and power procurement. I have delivered expert testimony on utility planning and operations, including rate design and cost of service, tariff administration, generation, transmission, distribution and customer service operations, load forecasting, demand-side management, capacity and system planning, and regulatory issues.

I have also been engaged (as a subcontractor) to review utility performance before, during, and after outages resulting from major storms in the state of Washington (major windstorm), Missouri (summer storms and ice storm), Texas (Hurricane Ike), Jamaica West Indies (Hurricane Ivan), the two 2011 storms (tropical storm Irene and a major snow storm) that affected New Jersey, and to review the emergency plan of a New England utility. Some of these assignments were at the request of the utility and others at the request of a state utility regulator. Testimony, if prepared and filed, is listed in Exhibit HS-1.

I have been engaged by clients to review proposed distributed generation contracts and the operation and integration of generating assets within power pool operations, and I have advised the Board of Directors of a public power utility consortium. For a period of four years, I was engaged by a multiple site commercial real estate organization to manage its solicitation for the purchase of retail energy. As a subcontractor, I have performed management audits for the Connecticut Department of Public Utility Control and ratebase audits for the Public Utilities Commission of Ohio and the Oregon Public Utility Commission. I also provide (as a subcontractor) support for the Staff and Commissioners of the District of Columbia Public Service Commission for electric and gas rate cases.

I have led and/or participated in consulting projects to develop, design, optimize, and implement both traditional utility operations and e-commerce businesses. These projects focused on the marketing, sale, and delivery of retail energy, energy-related products and services, and support services provided to utilities and retailers.

From 1994 to the present, I have been President of Energy Tactics & Services, Inc. From 1996 to 1998 I was a Managing Consultant for AT&T Solutions. From 1990 to 1994 I was Vice President of Business Development for Cogeneration Partners of America. In that position, I was responsible for the development of independent power facilities, most of which were fueled by natural gas and oil.

From 1978 to 1990, I held positions of progressively increasing responsibility with Atlantic City Electric Company in generation, regulatory, performance, planning, major procurement, and permitting areas.

From 1971 to 1978, I was an Engineer or Project Engineer for Univac, Soabar, Bickley Furnaces and deLaval Turbine, designing card handling equipment, tagging and printing machines, high temperature industrial furnaces, and utility and industrial power generation equipment, respectively.

I received a Bachelor of Science in Mechanical Engineering (minor in Economics) from Carnegie-Mellon University and a Master of Science in Engineering Management (minor in Law) from Drexel University. I have also taken courses on arbitration and mediation presented by the American Arbitration Association, scenario planning presented by the Electric Power Research Institute, and load research presented by the Association of Edison Illuminating Companies. I have also taken courses in zoning and planning theory, practice, and implementation in both New Jersey and Pennsylvania.

Q. Have you previously submitted testimony in regulatory proceedings?

A. Yes. I have testified and/or presented testimony (summarized in Exhibit HS-1) before the following regulatory bodies:

- Arizona Corporation Commission
- Delaware Public Service Commission

- Georgia Public Service Commission
- Jamaica (West Indies) Electricity Appeals Tribunal
- Maine Public Utilities Commission
- Maryland Public Service Commission
- Michigan Public Service Commission
- Missouri Public Service Commission
- New Jersey Board of Public Utilities
- Public Utilities Commission of Ohio
- Pennsylvania Public Utility Commission
- Public Utility Commission of Texas

DIRECT TESTIMONY

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Utilities Division Staff ("Staff") of the Arizona Corporation Commission ("Commission").

Q. What is the purpose of your testimony?

A. My testimony summarizes the review performed by Blue Ridge Consulting Services, Inc. ("Blue Ridge") of the UNS Electric, Inc.'s ("UNSE" or "Company") electric system quality, maintenance practices, and distribution system reliability indices. We reviewed the Company's peak demand, system energy, numbers and types of customers and system losses. Blue Ridge also reviewed the "used and usefulness" of assets included in the proposed rate base which were subject to field inspections. The review of the Company's acquisition of a portion of the Gila River Power Plant ("Gila River") is beyond the scope of Blue Ridge's engagement and will be addressed by Staff witness Barbara Keene.

Q. How was the review structured?

A. Drawing on Blue Ridge's and my experience in performing management audits, examining operations and field reviews of assets, we structured a review that investigated the items listed above using a number of interlocking techniques often used in management and operational audits. These techniques are designed to cross reference various items and methods of review to ensure that the utility has expertise, processes, and procedures that together provide a reasonable result for their customers.

Our work planning included defining specific data requests and reviewing the Company's responses before interviews and on-site visits, requesting interviews covering relevant areas of the Company, performing field visits to verify both the existence of an asset and to observe the condition of that asset, performing analysis of various data, and considering the reasonableness of the Company's efforts overall.

In order to verify that the processes supporting the above items are appropriate, we also examined the planning process of the Company.

Q. What data did you request?

A. We made data requests covering the following areas:

- Background Information[1]
- Planning Process[2]
- Load Research[3]
- Customer and/or Load Information[4]
- System Loss Studies[5]

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[1] UNSE response to STF 2.001.
[2] UNSE response to STF 2.002 through 10, 72.
[3] UNSE response to STF 2.014 and 5.1.
[4] UNSE response to STF 2.016 through 20 and STF 9.2.

- Construction Standards[6]
- Service Quality[7]
- Operations Staffing[8]

Additionally, we selected twelve major projects and generated a questionnaire that was to be completed for each project.[9]

Q. What issues did the questionnaire address?

A. The questionnaire addressed the following issues:

1. Reason for the project
2. Capital Budget (in or out of budget)
3. Dateline
4. Engineering determination
5. Cost estimate history
6. Constructed by employees and/or contractors
7. Safety
8. Off-site assembly
9. As-built drawings completed
10. Testing process
11. Equipment warranties
12. Maintenance scheduled
13. Impact on subsequent O&M budget
14. Outages since in-service date
15. Accounting details

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[5] UNSE response to STF 2.062.
[6] UNSE response to STF 2.071.
[7] UNSE response to STF 4.11through 15, 17, 18, 19 and 20.
[8] UNSE response to STF 4.16.
[9] UNSE response to STF 3.01 through 012.

16. Salvage values
17. Retirements
18. FERC approvals required
19. Insurance claims

- Questions 1, 2, 3, 4, 5, and 18 are designed to explore the project and the capital budgeting process.
- Questions 6, 7, 8, 9, 10, and 11 are designed to explore construction management and purchasing-related issues and processes.
- Questions 12, 13, and 14 are designed to determine if the Company has or will adjust its maintenance processes.
- Questions 13, 15, 16, 17, and 19 are designed to provide information that can be used in the development of revenue requirements and are not considered in this review.

Q. What interviews did you request?

A. We made requests for interviews in the following areas:[10]

- Load Forecasting
- Load Research
- Capacity Planning
- Capital Budgeting
- Distribution Planning
- Transmission Planning
- Outage Management
- Distribution Engineering

[10] UNSE response to STF 2.026.

Q. What field visits did you request?

A. We initially requested field visits encompassing the twelve selected projects.[11] These projects were selected primarily on the magnitude of the dollar value of the project. Once we confirmed the transportation blanket,[12] we decided not to review each individual purchase of transportation equipment due to the somewhat routine nature and the lower cost per item in this blanket.

Project No.	Project Name	Site Visit
312000A	UNSE Transportation Equipment – purchase of vehicles or custom build vehicles (a blanket project)	Not applicable
311364S	Nogales Tap – Valencia 115-138kV Rebuild	Yes
3920644S	Vail to Valencia 138kV Line Land & Engineering	Yes
311164S	Valencia T2 Replacement Nogales	Yes
379064S	Vail to Nogales Tap 138 kV	Yes
314864S	Sonoita Breaker Replacement 115 to 138 kV	Yes
381064S	Kantor Transformer Replacement from 115 to 138 kV	Yes
312164A	Nogales Office Building Purchase	Yes
314164S	Santa Cruz Valley Fixed Axis PV System	Yes
398061A	Griffith Substation T2 Addition 230-69kV	Yes
312661B	69 kV Transmission System Replacements – Kingman (a blanket project)	Yes
314362S	Distribution System Integrity & Restoration – Lake Havasu (a blanket project)	Yes

Q. How are the Company's operations structured?

A. Outage management and dispatch procedures were explored for the Company's two separate operating areas. Santa Cruz operations is dispatched by Tucson Electric Power Company ("TEP") and Kingman/Lake Havasu operates its own outage center. Outage calls are received in the TEP call center and then dispatched to Santa Cruz or Kingman/Lake Havasu as required. Kingman/Lake Havasu uses an "on-call" lineman to respond to trouble calls.[13]

[11] UNSE response to STF 3.013.
[12] A "blanket" work order is used to budget for and accumulate costs of a number of smaller capital items or projects.
[13] UNSE response to STF 4.16.

The Company focuses its reliability efforts using annual worst performing circuits, a process used by many utilities. Distribution engineering at the Company can and has been supplemented by resources from TEP, the Company's affiliate, depending on the complexity of the project.

Q. What conclusions did you draw about the Company's electric system quality, maintenance practices, and reliability indices?

A. My conclusions are discussed below; however, it is important to frame the situation. The Company's service territory is primarily rural with a low density of customers. Systems serving this type of area are typically radial fed and therefore will have higher outage times due to the lack of automatic equipment and the long distances that individuals or crews responding to trouble calls have to travel.

Service Quality

We reviewed the service quality data from the Company as shown in the following chart.

Table 1: Service Quality Issues[14]

Service Quality Issues	2013	2014	2015
Outages 4 hours or more affecting 200+ customers			
Mohave	2	1	2
Santa Cruz	10	5	2
Customer Complaints (Service Outages or Power Quality)			
Result: Customer Problem	7	2	1
Transformer Failures			
Mohave	43	21	31
Santa Cruz	27	33	5

The table above was developed from reports provided by the Company in response to our data requests. These reports are detailed and indicate the date, time, and duration of major outages, along with the number of customers affected and the cause of the outage. The

[14] Outage data based on UNSE response to STF 4.11; Customer Complaints data based on UNSE response to STF 4.12; Transformer Failures data based on UNSE response to STF 4.17.

report also includes how the outage was reported and it is notable that some of the outages are indicated by the Company's Energy Management System and by customers' "no power" calls. A review of the causes cited allowed us to discuss (during interviews) how the Company analyzes outages and responds to them over the long term.

Service Reliability

The electric utility industry uses standardized measures of outage reporting, which have been defined by the Institute of Electrical and Electronic Engineers (IEEE) under its standard number P1366 "Guide for Electric Distribution Reliability Indices." The industry often uses the following relevant measures:

- Customer Average Interruption Duration Index ("CAIDI") is the weighted average length of an interruption for customers affected during a specified time period

- System Average Interruption Frequency Index ("SAIFI") is the average number of times that a customer's power is interrupted during a specified time period

- System Average Interruption Duration Index ("SAIDI") is the average duration of interruptions for customers served during a specified time period

The IEEE also recognizes the concept of Major Event Days ("MED"), which factors out events such as hurricanes, tornados, floods and other events that cannot be predicted, avoided and/or are considered not repeating. There is a specific methodology to identify a MED arithmetically and adjust the statistics.

Generalized averages for these indices are available, but any utility's performance must be evaluated within the context of its demographic and geographic characteristics. For example, a suburban utility with a high customer density can often respond to an outage much faster than a rural utility (due to shorter travel distances) and the compact configuration of its system may have inherent redundancy and more extensive automatic equipment, which will reduce outage times. Systems with high percentages of underground equipment may have lower outage rates but may take longer to repair if an outage occurs. Conditions, such as lightning, salt spray, and birds in a utility's service territory, may also impact the indices, although the utility can address some of the impact of these conditions by engineering design standards.

Table 2: IEEE Performance Indices Benchmark Standards[15]

Performance Indices IEEE Benchmark Standards	2012	2013	2014
CAIDI - 1st Quartile	<93	<92	<91
CAIDI - 2nd Quartile	94-110	93-107	92-104
CAIDI - 3rd Quartile	111-130	108-127	105-127
SAIFI - 1st Quartile	<.89	<.85	<.86
SAIFI - 2nd Quartile	.90-1.08	.86-1.08	.87-1.07
SAIFI - 3rd Quartile	1.09-1.39	1.09-1.36	1.08-1.33
SAIDI - 1st Quartile	<93	<85	<86
SAIDI - 2nd Quartile	94-126	86-115	87-115
SAIDI - 3rd Quartile	127-163	116-158	116-159

Table 3: Service Reliability Indices[16]

Service Reliability Indices UNS Electric	2010	2011	2012	2013	2014
CAIDI	61.17	71.04	68.79	61.32	65.75
SAIFI	0.88	1.51	1.46	1.78	0.87
SAIDI	53.92	107.26	100.51	109.36	57.25

[15] Institute of Electrical and Electronics Engineers (IEEE) Benchmark Year 2015, Results for 2014 Data, http://grouper.ieee.org/groups/td/dist/sd/doc/2015-09-Benchmarking-Results-2014.pdf.
[16] Source data: 2010 through 2012 – STF 4.38 from Docket No. E-04204A-12-0504.
Source data: 2013 through 2014 – UNSE response to STF 4.20, attachments 2013 Monthly and Annual Indices Report.xlsx and 2014 Monthly and Annual Indices Report.xlsx.

The information in Table 3 was initially provided by the Company as the combined performance of its Santa Cruz and Mohave operations. In the prior case, Staff recommended that the indices be available service area by service area. The Company was able to provide the data on the recommended disaggregated basis for 2013 and 2014.

The Company's performance for 2012–2014 shows the average customer experienced outages lasting about 65 minutes, which is among the first quartile of the EEI data. A customer would expect one or two outages a year, which is among the third or fourth quartile of the EEI data but not surprising due to the rural nature of the Company's service territory. Restoration took between one and two hours during that period, which is among the second quartile of the EEI data and is positive considering the Company's service territory.

Based upon the data trends, size of the Company, demographic and geographical conditions, and the above statistics, the service reliability of the Company is considered reasonable.

Safety

The Company's Senior Director is also the leader of Corporate Safety for both TEP and the Company. The Company uses a full-time "safety rover" to monitor Company crews and contractors. Weekly safety meetings are held and work-specific tailboard sessions are conducted. A Corporate Safety meeting is held monthly.

UNSE witness Terry Nay emphasized the Company's philosophy for operational safety by testifying to its "Target Zero" safety strategy, which includes elements of (1) active safety leadership, (2) increased employee involvement and engagement in safety activities, and hazard control and regulatory compliance. Based on this strategy, significant improvement has been made, reducing its total recordable incident rate from 4.85 in 2013 to 2.72 in 2014.[17] However, this still ranks higher than the 2.50 industry average reported by the Bureau of Labor Statistics for 2013.[18]

Based upon the processes described and the above statistics, the safety program of the Company is considered reasonable.

No specific recommendations are made for these areas of the review.

Q. What conclusions did you draw about the Company's assets?

A. Our evaluation included an examination of the results of the questionnaires (previously described in detail above), which contained no unusual replies or conditions.[19] For example, the Company reported a 1.6-minute outage due to a minor problem during start-up of a major transmission line. Most projects were completed under budget by the selected low bidder.

My field visits included two days in Tucson to accomplish the bulk of the interviews, including area management for both the Santa Cruz County operating area and the Kingman/Lake Havasu operating area. I spent a full day, starting in Nogales and north to Tucson, viewing the operations center and observing the capital projects in that area. During my time in Tucson and Nogales and the area in between, I also observed the electrical construction used and its condition. Another Blue Ridge employee spent portions of two days in Kingman and Lake Havasu viewing the operations center and observing the capital projects in that area. During the visits to the operating centers, we were able to observe the

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[17] Direct Testimony of Terry Nay, page 3, lines 14-24.

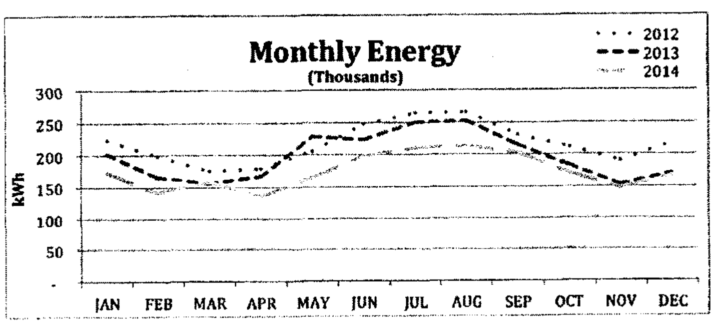
[18] 2013 BLS for Electric power generation, transmission and distribution (NAICS 2211), 50-249 employees.

[19] UNSE response to STF 3.01 through 3.12

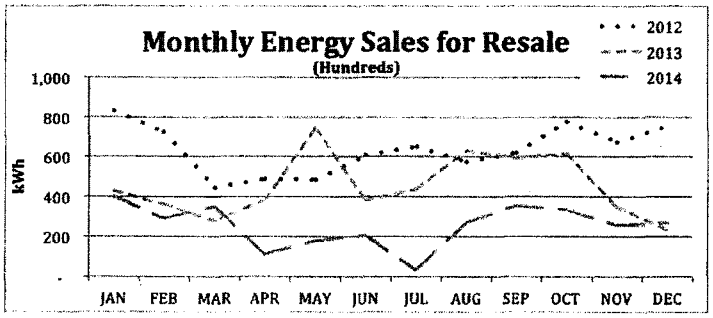
condition of the facility, storeroom, mobile equipment, and the yard. All of the locations and equipment observed during the field visits were in-place, appeared as described in the questionnaire responses, were reasonably maintained, and evidenced reasonable workmanship. Thus, all of the major rate base additions are considered used and useful. The values of the items will be determined and specified by Blue Ridge's Donna Mullinax, testifying on behalf of Staff. No specific recommendations are made for this area of the review.

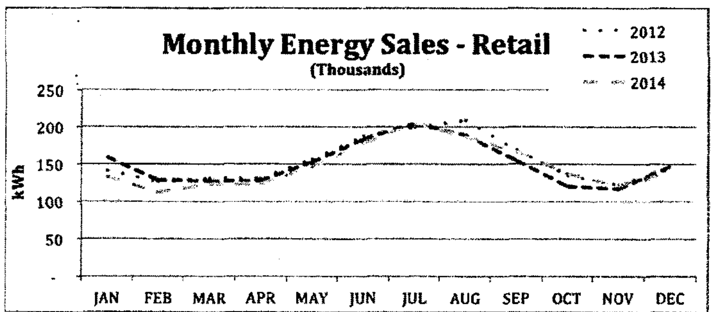
Q. What conclusions did you draw about the Company's peak demand, system energy, and the number and types of customers?

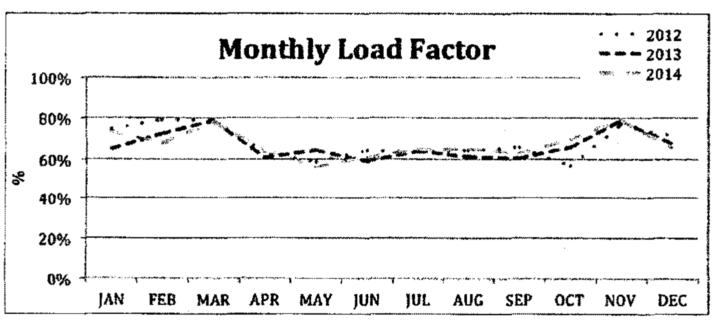
A. System energy and peak data were reviewed by month for the period 2012 through 2014.[20] Monthly load factors were calculated, and the data were plotted and examined. Data for individual customer classes were also examined, and the data plots were reviewed.[21] No unusual results were found. No specific recommendations are made for this area of the review.

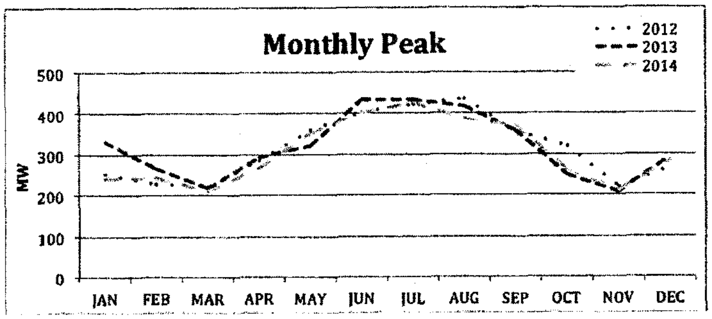


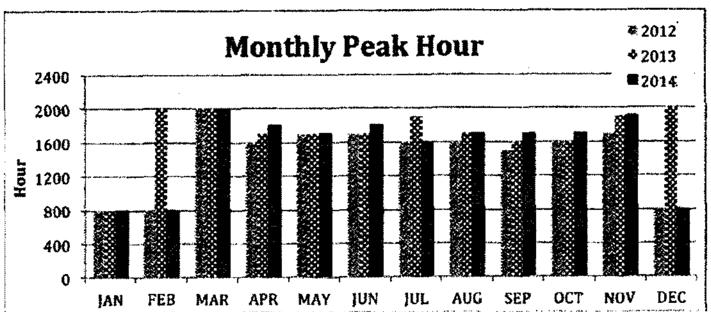
[20] UNSE FERC Form 1 page 401a
[21] UNSE response to STF 5.1


Monthly Energy Sales for Resale
(Hundreds)
2012
2013
2014
kWh
1,000
800
600
400
200
-
JAN FEB MAR APR MAY JUN JUL AUG SEP OCT NOV DEC


Monthly Energy Sales - Retail
(Thousands)
2012
2013
2014
kWh
250
200
150
100
50
-
JAN FEB MAR APR MAY JUN JUL AUG SEP OCT NOV DEC


Monthly Load Factor
2012
2013
2014
%
100%
80%
60%
40%
20%
0%
JAN FEB MAR APR MAY JUN JUL AUG SEP OCT NOV DEC





Q. What conclusions did you draw about the Company's system losses?

A. In the prior rate case, the Company did not have or provide a current system loss study.[22] The loss study provided in this case is a simple input-versus-output accounting study, covering 12 individual months at the transmission and distribution level.[23] The loss study provided does not include losses associated with transmission of energy over the interconnected Western Area Power Administration ("WAPA").[24]

[22] Docket No. E-04204A-12-0504 STF 2.23
[23] UNSE response to STF 2.062
[24] Company email from C Jones 10/13/15 @ 3:12 AM Item 4

Blue Ridge recommends that the Company perform a loss study covering various levels (equipment and voltage), such as transformation and line losses, which would require engineering input. This loss study should also be integrated with the Company's load research, which uses a different estimate of system losses.

Q. What conclusions did you draw about the Company's planning process?

A. The planning process was investigated to ensure that projects selected for construction are determined in an appropriate fashion based on reasonable planning criteria and processes. Without this foundation the usefulness of individual items cannot be determined. My review of the Company's planning process involved a number of areas.

Load Forecasting

The load forecasting process is a bare-bones process that is primarily performed for revenue forecasting. The residential class forecast is a bottoms-up methodology based upon the number of customers and the usage per customer, which is developed through regressions based on average temperature and inputs from multiple sources, such as IHS, local colleges, and public information. Separate forecasts are developed for Santa Cruz, Kingman, and Lake Havasu due to different weather conditions. The dispersion of the residential kilowatthours is made by allocation from past history.

The commercial forecast is driven from the residential forecast, which is not uncommon in the industry.

The large industrial forecast is a trend of the existing customers supplemented by information from some of those customers. Prior to 2015, the Company did not have any directly assigned account representatives.[25] The change to directly assigned representatives should provide better forward-looking information on this class.

The Company uses analysis and backcasting to determine the reasonableness of its models. The recent drop in summer usage has been somewhat perplexing to the Company, and the Company opined that distributed generation and energy efficiency could explain some of the drop and it might also be the result of more efficient lighting and air-conditioning. Therefore, the Company is considering the use of end-use models to enhance its forecasts.

The Company's load forecasting process is reasonable for the size of the Company and no specific recommendations are made for this area of the review.

Load Research

Load research utilizes the existing partially installed Advanced Metering Infrastructure ("AMI"). The Company's AMI installation is a one-way system using a fixed area radio network. For the residential class, approximately 1,000 AMI meters have been randomly selected to represent the class. The usage per customer of the AMI subset has been compared to the usage per customer of the customer base and determined to be a reasonable approximation. The commercial class is handled similarly. All industrial customers have interval meters (some of which are AMI), and the unmetered lighting class is calculated using the bulb wattage but does not include the associated lamp ballast loads.

The Company confirms the reasonableness of its load research by comparing the aggregated load to actual loads on its system. The Company uses an estimated loss factor of 9 percent, noting that WAPA charges an arbitrary 3 percent for losses across its transmission system.

[25] UNSE response to STF 2.072

This 9 percent loss factor is greater than the value used in the Company's loss study[26] in this case. The differences arise from the consideration of the losses due to transmission through WAPA and that the two loss factors are developed using different methods.

The Company is supplementing North American Industry Classification System data with Nielsen data to allow further analysis capability in the future.

Load research results are used by the Rates Department and, in the aggregate, by capacity planning. Distribution engineering generally depends on substation level data as opposed to load research.

The Company's load research process is reasonable for the size of the Company. Blue Ridge recommends the Company coordinate its loss factors for load research with an engineering-based loss study (recommended above).

Capacity Planning

The capacity planning review began with the impact of the two past Integrated Resource Planning ("IRP") analyses. The Company highlighted the concerns about UNSE's reliance on the energy market, which led to the purchase of the share of Gila River Unit #3 in concert with TEP. At present, the Company considers that it has significant flexibility at the Palo Verde hub, which offers access to 4,000 to 5,000 megawatts of capacity. Short-term supply planning is focused on having 90 percent of the Company's requirements under contract at the beginning of the calendar year and the remaining amount before the summer.

Using the load forecast and distributed generation impacts, the capacity planning group

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[26] UNSE response to STF 2.062

generates scenarios that include information/forecasts from multiple sources, such as McKinsey & Company, Pace Global, Energy Information Administration ("EIA"), and others. Besides the base plan, they also generate a number of scenarios required by the Commission.

The capacity plan is circulated to transmission planning, environmental, energy efficiency, renewables, corporate communications, and regulatory personnel. The approval process is somewhat informal as no transmittal document with required signatures is prepared but instead consists of a series of emails that reflect the various interchanges that occurred among the officers involved. Much of this interchange can occur at the regular Monday morning officers' meeting. Once the IRP is finalized it becomes the reference case and effectively drives the "corporate strategy/mission." Other important documents and plans, such as the energy efficiency implementation plan (June) and the renewable energy plan (July), are interconnected with the capacity plan.

The Company's capacity planning process is reasonable for the size of the Company and no specific recommendations are made for this area of the review.

Capital Budgeting

The Company's budget process has been accelerated by Fortis, requiring an earlier starting point (March/April). The capital budget begins with defining the number of full-time employees ("FTEs") available and considers the split between operations and maintenance ("O&M") and capital projects. The process covers 18 functional groups. The budget group issues a budget letter specifying customer counts, commodity costs, labor increases, and outside services. The contributors are asked for a five-year forecast (labor and material) that is detailed (monthly) for the first year and annualized for years four and five. Individual project contingencies are discouraged. Each of the individual areas generates a list of potential projects (and blankets), which are analyzed within the respective areas but are simultaneously tracked by the budget group. The individual groups' lists are culled down through an internal review; however, marginal projects (those not in the budget) are maintained (if needed later within the process).

In July, the various categories are rolled up for the Company and reviewed in a half-day session consisting of all officers, including the Chief Executive Officer. The individual areas make the presentations; however, the budgeting group adds costs for standard items, such as Allowance for Funds Used during Construction and Administration & General along with estimated in-service dates.

The financial forecast, which provides a 10-year view, is generated in September and October. The Rate Department, which has continuing input, focuses on the rate impact of the financial forecast. This forecast can be used to trigger events such as financings and rate cases. The board approves the capital spent in December and reviews the financial forecast, which is approved at the February board meeting. In the future, this approval is expected to happen by December to meet Fortis's requirements.

After approval by the board, a monthly budget review meeting reviews the results. The budgeting group provides monthly spend and quarterly and year-end reforecasts. The focus is O&M and occurs at months 2, 5, and 8. Variances are reviewed based on a standard of $200,000 per project, and any variance over $500,000 requires officer review. Projects not in the budget are also measured. By definition, a deferral is due to internal causes, and a delay is due to external causes. While the budgeting group assembles the information, each business area is responsible for its budget.

The Company's capital budgeting process is reasonable for the size of the Company, and no specific recommendations are made for this area of the review.

Transmission Planning and Engineering

Transmission planning and engineering are provided by the Company's affiliate, TEP. The Company considers this relationship to function well. Due to the size of the Company, its use of services from TEP is appropriate. Any review of transmission planning and engineering should be performed as part of a TEP proceeding.

Distribution Planning and Engineering

Distribution planning and engineering are provided by the Company's operating areas (Santa Cruz and Kingman/Lake Havasu) to take advantage of knowledge of local conditions, history, and construction. Distribution circuits are reviewed on a worst performing circuit basis and corrective action is defined and implemented. Remedies include additional segmenting of circuits to reduce the number of customers affected, bird guards, and wire. When needed for specialized situations, such as pole lines in high wind areas, the Company's distribution engineers obtain assistance from the Company's affiliate TEP. Due to the size of the Company, using services from TEP is appropriate.

Considering our observations of distribution construction, outage data, and interviews with area management, performance is reasonable for the size of the Company, and no specific recommendations are made for this area of the review.

Q. What relevant recommendations were made in the prior rate case?

A. As part of Staff's prior case (Docket No. E-04204A-12-0504), W. Michael Lewis, P. E. submitted testimony on June 28, 2013. That testimony included six recommendations of which three are relevant to this case.

Recommendation #1 which stated:

> "We recommend that UNS Electric have its distribution quality of service indices available, upon request, for review by Staff on a monthly and calendar year basis. Additionally, we recommend that these indices be by calendar year on a service area by service area basis, as well as on an overall system-wide basis. These indices are the Customer Average Interruption Duration Index ("CAIDI"), the System Average Interruption Frequency Index ("SAIFI"), and the System Average Interruption Duration Index ("SAIDI")."

Blue Ridge developed data request STF 4.20, then examined the Company's response, which includes service quality indices in the aggregate for the Company and on a service area basis for the Kingman/Lake Havasu and Santa Cruz areas. The Company has met this prior recommendation, which should continue.

Recommendation #3 which stated:

> "We recommend that UNS Electric prepare on an annual basis a listing of the worst performing circuits identified by service area and reliability indices and adopt a program similar to that implemented by TEP to target annual circuit maintenance toward circuits identified by indices value and survey as representing the most efficient means of improving SAIFI values."

Blue Ridge developed data request STF 4.14 and STF 4.20, then examined the Company's responses, which includes the Company's 2013 and 2014 Critical Circuit Analysis for the Kingman/Lake Havasu and Santa Cruz areas, which includes service quality indices and worst performing circuits for the Kingman/Lake Havasu and Santa Cruz areas.

The Company has met this prior recommendation, which should continue.

Recommendation #5 which stated:

> "UNS Electric maintenance scheduling should continue to include thermal scanning of the substation/switchyard bus and connected lines on a regular basis, including the BMGS."

Blue Ridge developed data request STF 4.20, and then examined the Company's response, which includes thermal scanning results for substations. The Company has met this prior recommendation, which should continue.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Testimony - Howard Solganick

Arizona Corporation Commission
Case – UNS Electric Docket No. E-04204A-12-0504 (June 2013 and July 2013)
Client - Staff of the Arizona Corporation Commission
Scope - Testimony covered revenue decoupling, cost of service, revenue allocation, rate design and other related issues.

Case – Tucson Electric Power Company Docket No. E-01933A-12-0291 (December 2012 and January 2013)
Client - Staff of the Arizona Corporation Commission
Scope - Testimony covered revenue decoupling, cost of service, revenue allocation, rate design and other related issues.

Case – Arizona Public Service Company Docket No. E-01345A-11-0224 (November and December 2011)
Client - Staff of the Arizona Corporation Commission
Scope - Testimony covered revenue decoupling, cost of service, revenue allocation, rate design and other related issues.

Public Service Commission of Delaware
Case - Delmarva Power & Light Company Docket No. 10-237 (October 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and miscellaneous charges.

Case - Delmarva Power & Light Company Docket No. 09-414 (February 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and weather normalization.

Case - Delmarva Power & Light Company Docket No. 09-277T (November 2009)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered an analysis of a straight fixed variable rate design for small gas customers and implementation issues.

Case - Delmarva Power & Light Company Docket No. 06-284 (January 2007)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization or normalization.

Georgia Public Service Commission
Case – Atlanta Gas Light Company Docket No. 31647 (August 2010)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered revenue forecast, cost of service, revenue allocation, rate design and other related issues.

Case – Atmos Energy Corporation Docket No. 27163 (July 2008)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered rate design and other related issues.

Jamaica (West Indies) Office of Utility Regulation
Case - Electricity Appeals Tribunal (August 2007)
Client - Jamaica Public Service Company, Ltd.
Scope - "Witness Statement" on behalf of the Jamaica Public Service Company Limited. This Statement covered issues relating to recovery of expenses incurred due to Hurricane Ivan.

Maine Public Utilities Commission
Case - Northern Utilities, Accelerated Cast Iron Replacement Program Docket No. 2005-813 (2005)
Client - Public Advocate of the State of Maine
Scope - Testimony covered an analysis of the program's economics and implementation.

Public Service Commission of Maryland
Case - Chesapeake Utilities Corporation Case No. 9062 (August 2006)
Client - Office of the Maryland People's Counsel
Scope - Testimony covered cost of service, rate design and other related issues.

Case - Baltimore Gas & Electric's (1993)
Client - As president of the Mid Atlantic Independent Power Producers
Scope - Testimony covered BG&E's capacity procurement plans.

Michigan Public Service Commission
Case - Consumers Energy Company Case No. U-15245 (November 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered cost of service, rate design and revenue allocation.

Case - Consumers Energy Company Case No. U-15190 (July 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy's gas revenue decoupling proposal.

Case - Consumers Energy Company Case No. U-15001 (June 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy and the MCV Partnership.

Case - Consumers Energy Company Case No. U-14981 (September 2006)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues relating to the sale of Consumers interest in the Midland Cogeneration Venture.

Case - Consumers Energy Company Case No. U-14347 (June 2005)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope – Testimony covered cost of service and revenue allocation.

Missouri Public Service Commission
Case – AmerenUE Storm Adequacy Review (July 2008)
Client – KEMA/AmerenUE
Scope – Oral testimony covered KEMA's review of AmerenUE's system major storm restoration efforts.

Case – Veolia Energy Kansas City, Inc. File No. HR-2011-0241 (September 2011)
Client – City of Kansas City, Missouri
Scope – Testimony covered various aspects of the Company's tariff provisions and the impact on the City of Kansas City.

New Jersey Board of Public Utilities
Case - Cogeneration and Alternate Energy Docket # 8010-687 (1981)
Case - PURPA Rate Design and Lifeline Docket # 8010-687 (1981)
Case - Atlantic Electric Rate Case - Phases I & II Docket # 822-116 (1982)
Case - Power Supply Contract Litigation – Wilmington Thermal Systems Docket # 2755-89 (1989)
Case - NJBPU Atlantic Electric Rate Case - Phase II (1980-81) Docket # 7911-951 (Before the Commissioners of the New Jersey Board of Public Utilities)
Client - Employer was Atlantic City Electric Company.
Scope - The cases listed above covered load forecasting, capacity planning, load research, cost of service, rate design and power procurement.

Public Utilities Commission of Ohio
Case - The Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company Case 07-551-EL-AIR (January 2008)
Client - Ohio Schools Council
Scope - Testimony covers issues related to rate treatment of schools.

Case - The Application of the Columbus Southern Power Company 08-917-EL-SSO and the Ohio Power Company Case 08-918-EL-SSO (October 2008)
Client - Ohio Hospital Association
Scope - Testimony covers issues related to rates for net metering and alternate feed service and related treatment of hospitals.

Pennsylvania Public Utilities Commission
Case - York Water Company Docket No. R-00061322 (July 2006)
Client - Pennsylvania Office of Consumer Advocate
Subject - Testimony covered cost of service, rate design and other related issues, also supported the settlement process.

Case – Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2010)
Client – Municipal Sewer Group
Subject - Testimony covered capacity planning, construction, treatment of future load and associated revenue, cost of service, rate design, capacity fee and other related issues.

Case – Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2008)
Client – Municipal Sewer Group
Subject - Testimony covered cost of service, rate design, capacity fee and other related issues, also supported the settlement process.

Public Utilities Commission of Texas
Case – Determination of Hurricane Restoration Costs Docket No. 36918 (April 2009)
Client – CenterPoint Energy Houston Electric, LLC
Subject – Testimony covered the reasonableness of the client's Hurricane Ike restoration process for an outage covering over two million customers and a restoration period of 18 days

EXHIBIT
S-5
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

SUSAN BITTER SMITH
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
DOUG LITTLE
Commissioner
TOM FORESE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. 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 UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS	DOCKET NO. E-04204A-15-0142

DIRECT

RATE DESIGN TESTIMONY

OF

HOWARD SOLGANICK

FOR THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

DECEMBER 9, 2015

TABLE OF CONTENTS

EXHIBITS

EXECUTIVE SUMMARY
UNS ELECTRIC CORPORATION
DOCKET NO. E-04204A-15-0142

Mr. Solganick's direct rate design testimony reviews the UNS Electric, Inc. ("UNSE" or "Company") proposal for cost of service, revenue allocation, rate design, and modifications to the Lost Fixed Cost Recovery mechanism (LFCR").

Mr. Solganick co-presents the Arizona Corporation Commission ("Commission") Utilities Division Staff ("Staff") recommendation that the Commission promulgate a long-term plan of rate design for UNSE and its customers. This plan responds to the schedule for installation of advanced metering and the opportunities it affords.

Staff recommends that the long-term rate design should focus on a three-part rate (customer, demand and energy) including time-of-use ("TOU") to better and more accurately relate rates to underlying costs. Staff also proposes the timing of the implementation of this plan and the further efforts that UNSE must take to provide customers with the information they need to respond to the more accurate three-part rate design. UNES should also develop an education program to help customers understand their usage information and how customers can manage their usage and change the size of their bills.

Mr. Solganick evaluates UNSE's Class Cost of Service Study and places its results into perspective and recommends that it be used as a guide to revenue allocation and a source of unit cost data for rate design.

Mr. Solganick provides the Staff recommendation for the allocation among the five major rate classes of Staff's recommended rate increase. This recommendation is tempered by the concept of gradualism due to the changes in rate base and changes in UNSE's recommended cost allocation methodology.

Based on a review of UNSE's application and responses to Staff data requests and consistent with Staff's long-term rate design plan, Mr. Solganick provides recommendations for the rate design for each of UNSE's five rate classes along with Customer Assistance Residential Energy Support ("CARES"), interruptible rates, distributed generation, service fees, the Buy-Through provision, Automated Metering Infrastructure ("AMI") Opt-Out customers and Economic Development proposals of UNSE.

Staff recommends that the Commission accept UNSE's proposal to eliminate the Fixed Charge Option from the LFCR mechanism. Staff recommends that the Commission reject the Company's other LFCR proposals and proposes the elimination of the DG portion of the LFCR in the Company's next rate case.

INTRODUCTION

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

A. My name is Howard Solganick. I am a Principal at Energy Tactics & Services, Inc. My business address is 810 Persimmon Lane, Langhorne, PA 19047. I am performing this assignment under subcontract to Blue Ridge Consulting Services, Inc. ("Blue Ridge").

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Utilities Division Staff ("Staff") of the Arizona Corporation Commission ("Commission").

Q. Have you previously submitted testimony in regulatory proceedings?

A. Yes. I have testified and/or presented testimony (summarized in Exhibit HS-1) before the following regulatory bodies:

- Arizona Corporation Commission
- Delaware Public Service Commission
- Georgia Public Service Commission
- Jamaica (West Indies) Electricity Appeals Tribunal
- Maine Public Utilities Commission
- Maryland Public Service Commission
- Michigan Public Service Commission
- Missouri Public Service Commission
- New Jersey Board of Public Utilities
- Public Utilities Commission of Ohio
- Pennsylvania Public Utility Commission
- Public Utility Commission of Texas

Q. Have you previously submitted testimony in this proceeding?

A. Yes. I previously provided testimony relating to the engineering analysis of the UNS Electric, Inc.'s ("UNSE" or "Company") rate base items, service reliability, and planning process on

November 6, 2015. My previous testimony in this case includes a summary of my background, qualifications, and experience.

Q. What is the purpose of your rate design testimony?

A. My testimony provides Staff's long-term plan of rate design for UNSE, analyzes the Company's Class Cost of Service Study ("CCoSS"), recommends an alternate allocation of the revenue increase proposed by Staff, and recommends how the increased revenue should be implemented within the Company's various existing and proposed rates, including a mandatory transition to Three Part-TOU rates for residential and small general service customers. I also present Staff's recommendations to address Customer Assistance Residential Energy Support ("CARES") rates, interruptible rates, distributed generation ("DG"), Service Fee charges, Buy-Through provision, Automated Metering Infrastructure ("AMI") Opt-Out and economic development. Finally, I present Staff's recommendations for the existing Lost Fixed Cost Recovery ("LFCR") mechanism. Some of these topics are also addressed in the direct rate design testimony of Staff witness Thomas M. Broderick.

DIRECT TESTIMONY

Q. Please summarize Staff's positions?

A. Staff recommends:

Long-Term Rate Design Plan

Rates should be based on costs and recognize the concepts of customer, demand and energy including time-of-use ("TOU"). When changes are made gradualism should be recognized. This plan is placed into the context of evolving metering and customer information capabilities.

Class Cost of Service Study

The purposes of a CCoSS are discussed along with the changes in the Company's CCoSS including a new production cost methodology. Staff recommends the use of Average and Excess-NCP, which the Company is proposing.

Revenue Allocation

Staff recommends a revenue allocation among the customer classes based on moving all classes to cost of service but recognizing that gradualism is necessary due to the effects of a new production cost methodology and the Company's inclusion into rate base of a portion of the new Gila River Unit #3.

Rate Design

Staff recommends rate designs for each rate schedule and consistent with the long-term rate design plan recommends the mandatory transition of residential and small general service rates (including DG customers) to Three Part-TOU rates. Staff also highlights areas where the Company should provide further information and justification for its proposals.

Staff highlights that due to the changes proposed the Commission should keep the rate design portion of the case open to resolve unanticipated customer rate impacts.

Miscellaneous Items

- CARES – Staff recommends that the level of this discount not be reduced and that a CARES provision for the new Three Part-TOU rate should be developed.

- Interruptible Rates – Staff recommends that the Company's proposed new interruptible Rider R-12 be adopted and that the existing IPS rate should be eliminated at the end of the Company's next rate case.

- Distributed Generation – Staff notes that Commission Docket No. E-00000J-14-0023, which is intended to examine the value and cost of DG, may provide useful information to the parties in this rate case. Therefore, for the time being, Staff does not propose any changes to the existing net metering tariff or waivers of the net metering rules but it may update its position in its Surrebuttal testimony or later at the hearing in this case. If ultimately the Commission continues to rely upon net metering, the migration to a three-part tariff will not pose any issues as the energy kWh charges in a three-part tariff and on a time-of-use basis would be used for net metering.

- Service Fee Charges – Staff analyses the Company's proposals and recommends which fees should apply to Opt-Out customers.

- Buy-Through – Staff looks forward to the input of other parties and does not object to this mechanism if there are no adverse impacts and no costs to other customers.

- AMI Opt-Out – Staff recommends that a non-transmitting solid-state meter be used to accumulate information needed for Staff's long-term rate design plan and the transition of Opt-Out customers to the Three Part-TOU rate along with recommended charges for the installation of the meter and monthly meter reading.

- Economic Development – Staff supports the establishment of the program but does not support any request for lost revenues.

LFCR

Based on a review of the Company's application, supporting testimony, and responses to data requests, Staff recommends that the Commission reject the Company's proposed changes to the LFCR mechanism that include:

- Allowing the Company to receive recovery for generation costs;
- Increasing the recovery for distribution demand costs from 50 percent to 100 percent;
- Increasing the cap on recovered costs allowed for each year from 1 percent to 2 percent;
- Expanding the LFCR mechanism to include revenues lost from a "Buy-Through" provision to be established in the Company's tariff; and
- Combining the Energy Efficiency ("EE") and DG portions of the mechanism on the customer's bill.

Based on a review of the Company's application, supporting testimony, and responses to data requests, Staff recommends that the Commission accept the Company's proposed change to the LFCR mechanism to eliminate the Fixed Cost Option.

Staff recommends that the DG portion of the LFCR mechanism:

- Be applied only to lost fixed costs from the end of the Test year to the rate effective date
- Be eliminated in the Company's next rate case.

LONG-TERM RATE DESIGN PLAN

Q. Are significant changes occurring in the Company's capability to measure how and when customers are using energy?

A. Yes. Based upon discussions between Staff and the Company, the Company expects to complete a significant majority (subject to a few geographic limitations) of its installation of AMI by the middle of 2016.[1]

Q. How has electric metering changed over time?

A. Initially there was no metering and infant utilities charged either a flat rate per customer or charged by the number of light bulbs installed by a customer. This pricing methodology is still used for lighting (and other fixed load) customers because the number and wattage of bulbs can be accurately verified and enumerated. By not using meters, the costs of meters and meter reading do not need to be charged to those customers.

With the advent of energy meters at a reasonable cost, coupled with a wider range of lighting and appliances, utilities began to charge customers based upon the energy consumed. This type of rate design did not recognize different costs based upon demand (often expressed as load factor). Two customers using identical amounts of energy but with different usage patterns could have different levels of demand and require different amounts of generation, transmission and distribution equipment (at very different costs), and therefore one customer may be undercharged and the other overcharged if demand was not measured and taken into

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[1] UNSE Response to STF 2.022

account. Alternatively, 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.

The introduction of demand meters, which measure peak demand usage within the billing period along with energy consumed, allowed for the introduction of rate forms such as the three-part rate (customer, demand and energy) or a variant (hours of use). The use of the demand meter and associated rates reduced the disparate impact of energy-only rates. Demand meters have generally not been used for residential customers due to the cost of the more complex meter, and the increased complexity of billing and the information that should be provided to the customer. The residential class was often seen as homogenous enough not to have wide usage disparities and therefore the cost of demand meters and their associated rate complexity was not justified.

For a number of years utilities have been able to measure the consumption of energy over very narrow time periods (hourly or even 15 minute intervals) but the challenge has been recording that data cost effectively and then providing that data to customers so that the customer could decide whether and how to respond and change their usage (energy) or usage pattern (demand). Interval data has been used for load research to provide an understanding of how different customers use energy and the data were typically recorded on magnetic tape and analyzed in bulk. While interval data were suitable for load research purposes, it was difficult to provide the data to a large number of customers at a reasonable cost.

Similarly, time-of-use meters could accumulate energy usage in a few time-differentiated periods but these data were only recorded and reported as On-Peak, Shoulder and Off-Peak and did not offer much information to the customer, such as when the energy was used on an interval basis.

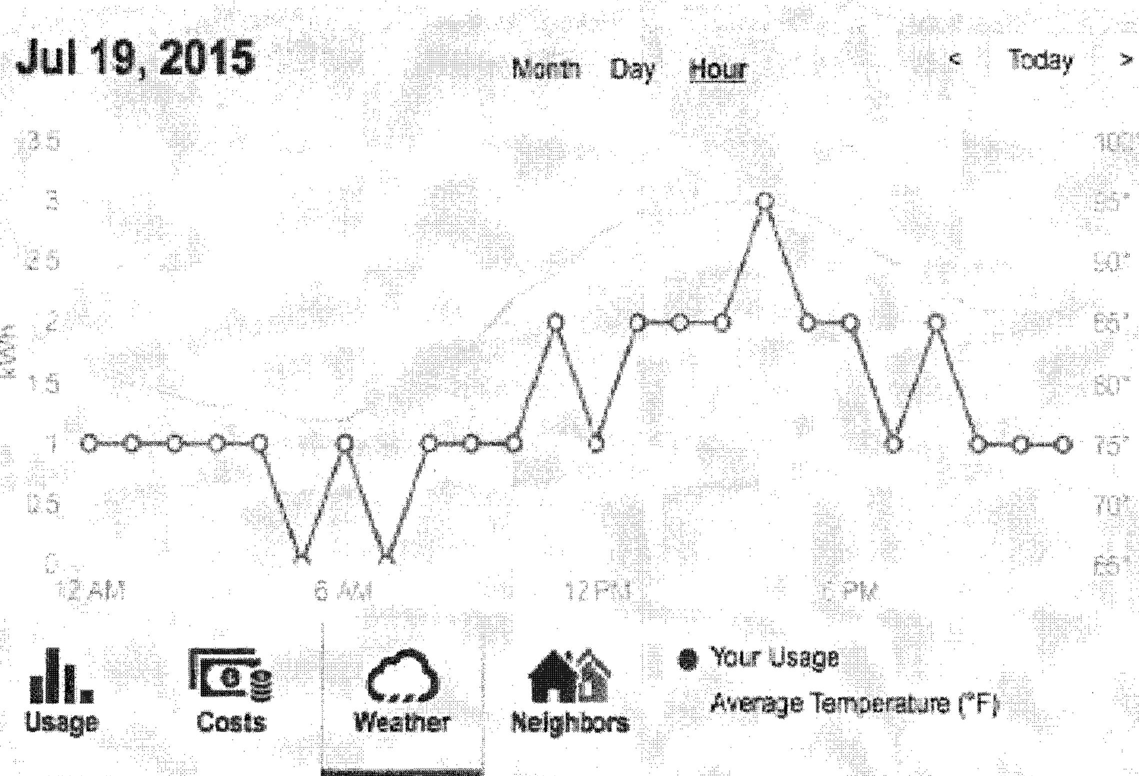
AMI has benefited from the declining costs of electronic versus mechanical metering devices and the ability to analyze data on a customer-specific basis. Utilities that have installed AMI often develop meter data management systems that allow for the extraction of energy and demand data for billing purposes. Unfortunately, some AMI planning does not go far enough and some utilities cannot provide individual customers their usage information in a form that supports customers' decisions about how and when to use energy more effectively and efficiently.

Q. Can you provide an example of conveying energy information to customers?

A. As a residential customer, my electric utility provides me with access to a portal where I can view my energy consumption.

On a macro basis, I can view my monthly consumption and compare it to an aggregate grouping of my neighbors and to a more limited aggregate grouping of my most efficient neighbors. The aggregate nature of these data protects my neighbors' privacy, and the portal limits my neighbors' access to my data, protecting my privacy. Various entities have opined that providing this "new" data encourages some customers into becoming more efficient in their use of energy.

My utility also provides me (with a two-day delay) my hourly energy consumption, which is equivalent to hourly demand. From this timely information, I can determine the peak period(s) of energy usage and then decide if I wish to change my energy usage in the future.



Q. How did the confluence of new metering and information capabilities, changing customer characteristics and the Company's proposals in this case initiate a discussion with Staff?

A. At this point in time, many utilities have the capability to record interval data as a result of the installation of AMI. Some utilities can provide that data to individual customers in a form that is somewhat easily understood, although some customer education is necessary. 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.

Staff has raised the concept of offering a "plan" of how rate design should evolve so that the parties to this case could provide their input and the Commission could consider a plan in order to provide the Company's customers advance notice that changes are underway. As we considered potential positions in this case, the wisdom of Staff's suggestion became clear as it may assist customers as they make their individual long-term energy decisions.

Q. Please articulate the Staff's long-term rate design "plan".

A. There are a number of principles within this plan.

Rates should be based on costs derived from class cost of service studies not only at the class level but also to illuminate the unit costs of individual customer, demand and energy rates. Marginal costs should be given some consideration but embedded costs are the focus. There should be a place for test programs to determine if rate design can alter the need for capital investment and/or energy costs. When changes occur, gradualism should be used to temper the short-term impact until the next rate case.

Rate design should recognize the concepts of customer, demand and energy, and also recognize TOU and seasonality ("Three Part–TOU"). The number of rates available to customers should be minimized to avoid confusion as Three Part–TOU rates allow for cost-based billing of non-homogenous customers within one rate schedule. Inverted rates would be supplanted by the seasonal TOU component and the demand component which recognize load factor.

Generation pricing would reflect the marketplace by considering seasonality, TOU, hourly pricing and demand response.

Rates should be supported by customer-specific usage information collected under extreme privacy and security, but available to customers along with tools to help them see the impact and make decisions. In the long-term, customers might receive cost "warning" using a simple red/yellow/green indication in their home or business and, for example, their demand controllers could access detailed price information online.

Rate subsidies, as determined appropriate, should be clearly delineated, be based on and computed from standard rates. For example, a CARES customer would be billed as a standard residential customer including all trackers and adjustment clauses but also receive a specific discount amount. Should a CARES customer's situation change for the better, the only change would be the removal of the CARES discount, which would be easily recognized by that customer. Hence, Staff's plan migrates CARES eligible customers to the Three Part-TOU rate.

The Commission's Docket No. E-00000J-14-0023 will assist Staff and the parties to determine an adequate methodology and quantification of compensation to potentially replace net metering. Ultimately if DG results in savings across the utility system and differentially for specific geographic areas (feeder), these effects would in time be separately identified.

Q. Does migrating all customers of a class onto a single Three Part-TOU rate limit a customer's choice to one alternative?

A. Customers have very limited options now. The two-part rate allows the customer to increase or decrease his/her energy consumption to change the total bill. A two-part rate with TOU allows the customer to increase or decrease his/her energy consumption and when that energy is consumed but does not reflect the intensity or magnitude of use. The Three Part-TOU rate allows for a third dimension that the customer can use to affect the intensity of use.

One customer may come home from work, turn on the air conditioner, shower using hot water from an electric water heater and start the clothes washer all at the same time. A second customer may decide to linger with friends and have dinner out but have the air conditioner begin to cool the home before arrival, shower later in the evening and set the clothes washer to start at 4 AM. The intensity of multiple electric appliances operating together places a greater load on the system than the load of a single appliance. The Three Part-TOU rate prices the consumption and usage pattern differently by charging for both the demand (intensity) and energy consumed separately. In each case, the customers can choose the usage and pattern they wish and be charged appropriately for raising or lowering the utility's costs.

Q. Can you try another analogy?

A. Yes. A rental car customer decides what size car to rent. Larger or more expensive cars cost more per day, whether the car is driven or not. When driven, the renter pays for the gas. Rental car pricing may also be different on weekdays compared to weekends. The size of the car is similar to demand, the miles driven (gas purchased) is similar to energy, and the weekday/weekend similar to TOU. If one renter chooses a small car for weekday errands and another for a long weekend trip for a family of six, the final charges will be different.

Q. What would be the long-term impact of this rate design "plan"?

A. Customers would have greater information available to make their own energy decisions, and rates would more accurately price those decisions and lessen the consequential impact on other customers. Over time, customer and demand charges would gradually increase and energy charges would become "purer" and lower for the distribution component. A customer could reduce costs by adjusting demand and/or by changing energy usage. The customer benefits from tools and education to take the best advantage of new rate forms.

As the Three Part-TOU rate design becomes fully implemented, the magnitude of the LFCR will diminish and can be eliminated for DG, as it is a "fix" for rates that focus too highly on energy.

Q. Are these concepts new or new to the Company?

A. For medium and large customers demand rates have been the norm and a Three Part-TOU rate is available. Flat rates are still appropriate for fixed, predictable loads such as lighting, cable amplifiers and traffic signals.

In the previous UNSE rate case (Docket No. E-04204A-12-0504), I raised a number of these concepts but did not articulate them as a plan. Similarly, in this case the Company has raised some of these concepts but has not provided the data and education components critical for customer understanding of the Three Part-TOU rate design.

Q. What are the important transition principles for the move towards the long-term rate design plan?

A. Rate design should not be changed until customers have private, secure, easy, timely and comprehensible access to their usage data. Staff recommends that the Company develop and submit a detailed transition plan for Residential and Small General Service customers in its rebuttal.

As with most any mandatory transfers from old rate designs, the initial transfers should be done in phases. Customers with the opportunity to change their usage or usage patterns should be transferred first. This will generally imply that larger users within a class or rate who have many appliances and/or uses for energy and therefore have multiple opportunities to change the appliance stock and usage pattern would be transferred first. Customers who might have only lighting and refrigeration (low use) might be transferred last. Transferring customers in phases allows for testing of education and information transfer and is best tested with smaller customer classes first.

Q. What other actions might be needed during the transition?

A. The Commission should keep the rate case open beyond its revenue requirements decision to monitor the transition and deal with unknown problems if they occur. This period should last at least six months past any required transition period or a minimum of 18 months. The Commission has done this with prior cases[2]; however, I am not opining on the legal methodology to accomplish that.

The utility should monitor revenue by rate schedule and report (revenue and customer impacts) quarterly to Staff and changes in revenue should be analyzed on an annual basis.

The transfer from a two-part to a three-part rate may adversely affect certain customers. For example, school athletic field lighting that is separately metered (not as part of a school building complex) and uses energy a few times a year may see a significant impact on that particular bill. The Commission may wish to consider the impact of the rate design change on the total electric bills of the school or district and, if needed, institute a transitional "rate stopper" to limit the impact on the customer. The impact should be evaluated over at least a one-year period on the customer's total bills, not on a single bill or account basis. The impact should be balanced against the costs that the utility incurred when the school district decided to not connect the field into its internal wiring system (to save the district a capital expenditure). The Company can assist by identifying potentially affected customers. Staff

[2] ACC Decision No. 73912 page 73

witness Thomas M. Broderick provides more details about potential "vulnerable" customers in his testimony.

CLASS COST OF SERVICE STUDY

Q. What is the purpose of a fully allocated cost of service study?

A. Just as the rate case revenue requirements process studies each element of the Company's operations to determine the overall cost to operate the Company efficiently and effectively, a fully allocated cost of service study attempts to determine the individual cost to serve each customer class and subclass. A fully allocated cost of service study is intended to assist the Commission to allocate revenue requirements among customer classes.

Q. How can a regulator use the cost of service study?

A. Because customer classes use the utility's system on an interrelated or shared basis, regulators have historically used a fully allocated cost of service study as a guideline to allocate revenue among classes. Regulators typically also consider economic, social, historical and other factors that may affect customers when determining revenue allocation. Such considerations often result in rates that deviate from strict cost of service.

Q. Are there limitations to a cost of service study?

A. Yes. A cost of service study involves judgment and decisions on the part of the practitioner in assigning costs to the various customer classes. In some situations, decisions are made to use a particular allocation factor for a particular account. In other situations, data used to develop an allocation factor are not always complete and/or timely and the practitioner must deal with the resulting uncertainty. Consequently, the cost of service study acts as a guide in revenue allocation and in formulating rate design.

Q. Has the Company provided a class cost of service study?

A. Yes. The Company provided its CCoSS based on the Test Year (twelve month period ended December 31, 2014).[3] Schedule G provides the individual class returns for the Company's five major service classes (Residential, Small General Service, Medium/Large General Service, Large Power Service and Lighting).

Q. Have you reviewed the CCoSS presented by the Company?

A. Yes. The CCoSS was provided as Schedules G-1 through 7. I performed a review of the allocations, developed data requests and reviewed the answers to Staff and other parties. I conducted informal technical conferences with the Company to understand certain aspects of the CCoSS.

Q. Did the Company adjust or normalize its revenues?

A. Yes. The Company used a Test Year (twelve months ending December 31, 2014) and then adjusted it to reflect more normal or appropriate (from the Company's viewpoint) conditions.[4]

Q. Has the CCoSS changed from the prior rate case (Docket No. E-04204A-12-0504)?

A. Yes. The prior CCoSS had six service classes (Residential, Small General Service, Large General Service, Large Power Service, Mining and Lighting). The Residential, Small General Service and Lighting classes are similar. The Company created new rate schedules for Medium General Service ("MGS") and Large Power Service ("LPS") based on demand and voltage criteria from the former Large General Service ("LGS") and Large Power Service rate schedules.[5]

[3] UNSE Filing Schedule G
[4] UNSE Filing Schedule G-1 lines 41 and 44; Schedule G-2 lines 39 and 42
[5] Jones Direct 44:4 and 44:12

Q. Are the changes to the service classes appropriate?

A. Yes. The differentiation by demand and voltage proposed by the Company is appropriate. The combination within this case's CCoSS of Medium General Service and Large General Service classes should be disaggregated in the Company's next CCoSS as the transition to the MGS rate schedule will have been completed.

Q. Have the Company's capacity resources changed since the last case?

A. Yes. The Company recently purchased a 25 percent share of the Gila River Power Plant Unit #3 combined cycle generating plant in concert with its affiliate Tucson Electric Power ("TEP").[6]

Q. Please describe the attributes of a typical combined cycle generating unit?

A. A combined cycle generating unit is flexible in that it can start and stop operations (dispatch) easier than a coal or nuclear plant and is generally more thermally efficient than most other forms of fossil and nuclear generation. Typically combined cycle plants are fueled by natural gas with distillate oil backup.

Q. What allocators does the Company use for its power supply expenses within the 2014 CCoSS?

A. For Other Production Plant, the Company uses the DPROD allocator, which is classified exclusively as demand.[7] For Other Production Expenses, the Company uses the EFUEL allocator, which is classified exclusively as energy.[8] For Purchased Power Expenses the Company uses the EFUEL allocator for energy charges, which is classified exclusively as energy.[9]

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[6] Hutchens Direct 2:6 and 8:6
[7] UNSE Schedule G-3, Sheet 4, lines 14-20
[8] UNSE Schedule G-4, Sheet 4, line 18
[9] UNSE Schedule G-4, Sheet 4, line 29

Q. What allocator methodology did the Company use for DPROD?

A. The Company states that it used an Average and Excess allocator for production plant and expenses.[10]

Q. Has the Company changed the selection of the DPROD allocator since the last case?

A. Yes. Previously the Company used a Peaks and Average allocator in its 2012 CCoSS.[11]

Q. Is the Company's Average & Excess & 4CP allocator a standard production methodology?

A. Although the Company stated that it is using an Average and Excess allocator[12] it was non-specific in written testimony about the construction of the allocator. However, the Company provided a table within its testimony showing the impact of various allocators on class returns.[13] Within this table, the Company describes its Average and Excess allocator as Average & Excess & 4CP, which, based on the title, would be non-standard. Using coincident peaks (one or more) within the average and excess allocator is not a standard or recommended methodology.

Q. Why do you say that Average & Excess & 4CP does not appear to be a standard methodology?

A. The Electric Utility Cost Allocation Manual indicates:

> "If your objective is – as it should be using this method – to reflect the impact of average demand on production plant costs, then it is a mistake to allocate the excess demand with a coincident peak allocation factor because it

[10] Jones Direct 25:3
[11] Jones Direct 25:3
[12] Jones Direct 25:7
[13] Jones Direct 25:12

> produces allocation factors that are identical to those derived using a CP method. Rather, use the NCP to allocate the excess demands."[14]

Q. Did you explore this concern with the Company?

A. Yes. The Company indicated that the DPROD allocator is a traditional A&E-NCP allocator but is allocating the 4CP value, thus the use of 4CP as an identifier. The Company confirmed this in an email.[15]

Q. What is Staff's recommendation for an appropriate methodology for the DPROD allocator?

A. The appropriate methodology is Average and Excess-NCP (noncoincident peaks) as supported by the National Association of Regulatory Utility Commissioners ("NARUC") Manual as noted above. This allocator reflects both average load (energy) and excess load (demand) without algebraically becoming a CP allocator. This methodology is a better fit to a capacity plan that focuses on both energy and capacity (and selects an efficient and flexible generation technology). Based upon the Company's response, the Company's Average & Excess & 4CP allocator meets Staff's recommendation.

Q. Are there disproportional impacts between the present CCoSS and the prior one?

A. As Exhibit HS-2 shows, the change for the Residential and Small General Service classes is higher than the change for the Company in total. For example, Net Production Plant increased by 69 percent for the Company but 91 percent for the Residential class and 126 percent for the Small General Service class. Energy costs decreased 10 percent for the Residential class but less than the 16 percent decrease for the Company.

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[14] NARUC Electric Utility Cost Allocation Manual January, 1992, page 50
[15] Email from Craig Jones dated 10/13/15 3:12 AM Item 1

Q. Is the Company proposing to return deferred funds to customers?

A. Yes. The Company is proposing to return approximately $9.3 million to customers on a one-time basis.[16] This refund would flow through the Purchased Power and Fuel Adjustment Clause ("PPFAC") and therefore be effectively allocated on an energy basis.

Q. What is the result of the Company's capacity allocation proposal in this case?

A. The use of the new DPROD allocation methodology (A&E-NCP) raises the allocation to lower load factor classes (more costs), while the use of an energy allocation methodology for the deferred funds reduces the allocation (less savings) to the lower load factor classes.

Q. Is the Company's proposal to change to a new DPROD cost allocation methodology and return the deferred funds on an energy basis inappropriate?

A. The Company's allocation proposal is not inappropriate; however, the effects on lower load factor classes is significant because the proposal is accompanied by a significant increase in power production capital costs.

Q. What is the impact of the change to the DPROD allocator?

A. The Company provided a comparison of the impact of demand allocators (Average & Excess & 4CP and Peaks & Average & 4CP) after the Company's proposed increase.[17] Assuming that only the production plant allocation methodology has changed, the class return for the Residential class has gone from 6.82 percent using P&A to 6.00 percent using A&E; Small General Service class 8.90 percent to 6.40 percent; Medium/Large General Service 9.84 percent to 12.96 percent; Large Power Service 8.76 percent to 9.06 percent; and Lighting 10.84 percent to 7.87 percent; while the overall Company remained constant (as it should) at 7.93 percent.

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[16] Application page 6 (Table Gila River Deferred Savings)
[17] Jones Direct 25:11

Q. How have the returns of the classes changed between the present and prior CCoSS?

A. Exhibit HS-3 compares various items between the two CCoSS. In the 2012 CCoSS (12-0504) [line 12] all classes had positive class rates of return except the Mining class, while in the present CCoSS [line 33] the Residential and Small General Service classes have negative returns. A more consistent basis to compare returns uses the Unitized Rate of Return ("UROR") [lines 13 and 34], which is the class return divided by the Company return.

Q. Does the Company's allocation of income taxes by class have an impact on the returns calculated?

A. The Company appears to allocate class income taxes on the sum of return times rate base plus operating expenses (without income taxes). Using this methodology, positive taxes are allocated to a class that is not providing enough revenue to cover expenses. An alternative (sometimes used) calculates class income taxes based on the profitability of the class, more akin to how a business is taxed. This difference in methodology magnifies the disparity between positive and negative class returns. However, when all classes have positive returns close to the Company's return the effect is smaller and of less consequence than the other changes discussed above.

Q. What CCoSS recommendation does Staff have for the Commission?

A. There are two major effects operating in the same direction in this case. While the Company's net distribution plant has decreased by 1 percent, net production plant has increased by 69 percent. Simultaneously, the Company has changed its production plant allocation methodology from Average & Peak to Average & Excess–NCP. These two changes magnify the individual impact on classes, such as Residential and Small General Service. Therefore, the Commission should use the Company's CCoSS as a general guideline and invoke gradualism in its class revenue allocation decision for this case.

REVENUE ALLOCATION

Q. What non-cost considerations should the Commission consider during its deliberations on revenue allocation?

A. The Commission should consider the relative positions (from the CCoSS) of the classes along with the qualitative issues such as economic conditions for consumers, the business climate and past practices when deciding what portion of a revenue increase is allocated to each class. Also, the size of the classes limits how much the Commission can move a class at the conclusion of any single rate case. For example, the new Medium/Large General Service class is almost five times larger than the Small General Service class. The Residential class is six times larger than the Small General Service class and more than all other classes combined.[18]

Q. What principles do you use to allocate revenue among rate classes?

A. I have used the following principles:

- The individual rate classes should be gradually moved toward an UROR of 1.000 over one or more rate cases depending on the frequency of rate cases and the distance of the class' UROR from 1.000.

- There should be an upper bound of 150 percent for any class' percentage increase in revenue compared to the overall percentage increase in revenue.

- There should be a lower bound of 50 percent for any class' increase compared to the overall increase.

[18] Schedule G-1, Line 20 Total Electric Revenue From Sales

Q. Are there other concepts that apply in this case?

A. The purchase of the combined cycle generating unit was intended to stabilize energy costs, which provides benefits to all customers. Therefore, it would be inappropriate to reduce rates for any customer class because that would send a confusing message about the new plant expenditure.

Q. What is the Company's proposed revenue allocation?

A. Based on Schedules G-1 and G-2 [lines 22 and 20 respectively], the Company is proposing to allocate 91 percent of its requested $22.5 million increase to the Residential class, 11.8 percent to the Small General Service class, small amounts to the Medium/Large General Service classes and a reduction to the Large Power Service class.

Q. Have you modeled various revenue allocations based on Staff's recommended revenue requirements?

A. Exhibit HS-4 models Staff's proposed increase a number of ways. For comparison purposes the increase was allocated:

- Proportional to the Company's proposed revenue allocation percentages
- Equal percentage increase (across the board by revenue)
- Moving all of the classes to the same return (UROR equals 1.000)
- Moving the Residential and Small General Service classes 50 percent of the amount needed to reach parity (and increase all other classes by an equal 10.1 percent)
- Moving the Residential and Small General Service classes 60 percent of the amount needed to reach parity (and increase all other classes by an equal 6.3 percent)
- Moving the Residential and Small General Service classes 67.7 percent of the amount needed to reach parity (and increase all other classes by an equal 3.7 percent)
- Moving the Residential and Small General Service classes 75 percent of the amount needed to reach parity (and increase all other classes by an equal 0.5 percent)

Q. What is Staff's recommendation on revenue allocation?

A. Based upon the present and prior CCoSS, the principles discussed above, the impact of the purchase of the combined cycle plant and the relative impacts between classes, Staff recommends that the eventual revenue requirements be allocated by increasing the Residential and Small General Service classes 50 percent of the amount needed to reach parity and increasing all other classes by an equal 10.1 percent to obtain the total revenue requirement.

As shown within the box in Exhibit HS-4, under Staff's recommended revenue allocation the Residential and Small General Service classes receive 58.3 percent and 7.3 percent of the overall increase compared to the Company's proposal of 91.2 percent and 11.8 percent for those two classes respectively. Under Staff's proposal, all classes receive an increase while the Company's proposal decreased the revenue requirement for the Large Power Service class.

Q. If Staff's recommended revenue allocation is adopted what will the class returns be?

A. The results of the proposed revenue allocation are forecasted in Exhibit HS-4. All classes will have a positive return; the UROR of the "low UROR" classes (Residential and Small General Service) will increase and the UROR of the "high UROR" classes will decrease, moving all classes towards parity.

Q. Has the Residential class been subsidized by other classes in the past?

A. Yes. Exhibit HS-3 summarizes the Company's latest two CCoSS. In the 2012 CCoSS the UROR [line 13] is less than 1.0 for the Residential, Large Power Service and Mining classes indicating subsidization by the other classes. In the present CCoSS the UROR [line 34] is less than 1.0 for the Residential and Small General Service classes.

Q. Please explain why, if the Residential and Small General Service classes are being subsidized by other classes, Staff is not recommending class revenue increases to bring those classes to parity, which would be consistent with the rate design plan Staff is recommending and you have detailed above.

A. Staff's plan articulates the concept that "Rates should be based on costs derived from class cost of service studies…", however the plan is a *long-term* plan.

Exhibit HS-4 shows that to bring the Residential class to parity would require a class revenue increase of 116 percent of the total increase and an increase of 14.7 percent of the total increase for the Small General Service class (significantly higher than the Company's proposal). Exhibit HS-2 demonstrates that significant changes have occurred between the two CCoSS due to the impacts of the acquisition of a portion of Gila River Unit #3 and the change in the DPROD allocator.

As explained above, revenue allocation is not just an algorithm-based process but it is tempered by a Commission's evaluation of other factors. Also Staff's recommendation to move half way to removing the subsidy allows for the completion of the process in a following case.

RATE DESIGN

Q. Please summarize the Company's rate design proposal.

A. The Company's rate design objectives are "To align rate structures with our customers' evolving energy use", "To reduce the level of cross-subsidies between customers" and "To give the Company an appropriate opportunity to recover its fixed costs."[19]

[19] Hutchens Direct 6:16

The Company has focused on the use of a three-part rate design (customer, demand and energy charges) that would be mandatory for all new DG customers and optional for other Residential ("RES") and Small General Service ("SGS") customers.[20] The Company suggests that these changes are to better align the Commission's policies with the Company's need for fixed cost recovery and system usage.[21] The Company is also supporting gradualism when making rate design changes.[22] For new DG customers, the Company is proposing monthly bill credits for any excess energy delivered to the Company's system.[23]

Q. What was the Company's primary concern in developing its rate design proposals?

A. As I understand the Company's approach, the focus was on developing and then moving to a three-part rate in order to maintain the recovery of fixed costs. A concern is expressed that seasonal customers, vacant homes or businesses, and DG customers (with their associated low kWh consumption) limit the Company's ability to recover fixed costs.[24]

Q. Is this focus on fixed costs sufficient to support rate design changes?

A. If fixed costs are not properly accounted for in the rate design, intra-class subsidies will occur. The challenge is how to and how fast to make the changes. RES and SGS customers have a simple rate design and even the acceptance of TOU rates in these classes has been limited.[25] With new rate forms, some customers need education and support to achieve a meaningful transition.

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[20] Hutchens Direct 10:8, Dukes Direct 16:6 and 19.11
[21] Hutchens Direct 10:23
[22] Hutchens Direct 14:14
[23] Hutchens Direct 15:7
[24] Dukes Direct 11:14
[25] Schedule H-2-1 line 3 (230 customers)

Q. Is the Company's unit cost analysis in Schedule G-6-1 useful in evaluating its proposed customer charges?

A. Many of the concerns about the CCoSS do not apply to the direct customer costs. The Company also updated Schedule G-6-1 and the update should be used as a point of comparison.[26] The Company's information shows direct customer costs, an amount that includes meters, billing and collection, meter reading costs and the service line or drop. The Company has indicated that it used a minimum-sized system to allocate portions of the distribution system (such as poles, wires, transformers) to the customer component.[27] These costs are included in the customer-related unit costs.[28]

Q. What changes does the Company propose for the Residential Service (Rate RES-01) rate?

A. The Company is requesting an increase in the customer charge from $10.00 to $20.00.[29] Energy charges also are proposed to increase,[30] and the Company is proposing to eliminate the third tier for revenue stability reasons.[31]

Q. What changes does the Company propose for the TOU Residential Service (Rate RES-01 TOU) rate?

A. The Company is requesting an increase in the customer charge from $11.50 to $20.00 for TOU customers,[32] and adjustment in the rate to match the configuration of the Super Peak TOU rate.[33]

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[26] UNSE Response to STF 2.056 and STF 2.057
[27] UNSE Response to STF 2.069
[28] Email from Craig Jones dated 10/13/15 2:49 AM
[29] Jones Direct 40:23
[30] UNSE Schedule H-3, Page 1
[31] Jones Direct 42:1
[32] UNSE Schedule H-3, Page 1
[33] Jones Direct 42:13

Q. What are the residential customer costs?

A. The Company's information shows that direct customer costs are $14.73.[34] This amount includes meters, billing and collection, meter reading costs and the service (line or drop) and the components that form the minimum-sized system.

Q. What changes does Staff recommend to the RES-01 residential rate?

A. For the pre-transition period Staff recommends the following modifications of the Company's proposal:

- The existing rate design including the third tier (over 1,000 kWh) should be retained, but the inclination should be flattened by increasing all blocks by the same amount per kWh.

- All residential customer charges should be $15.00 to match the Company's costs. With the advent of AMI, all customers will be using the same meter.

- The revenue allocated to the Residential class should be collected first by an increase in the customer charge up to the level proposed here, with the remainder (if any) recovered by increased energy charges. Applying the revenue increase to the Customer Charge first will increase recovery of fixed charges and reduce the impact within the LFCR mechanism.

[34] UNSE Response to STF 2.057, Schedule G-6-1, Line 23 and Email from Craig Jones dated 10/13/15 at 2:49 AM

Q. What is the impact on residential customers of Staff's pre-transition recommendations?

A. Based upon Staff's recommended overall increase in revenue requirements along with its revenue allocation and pre-transition rate design changes, residential customers would see increases as shown in Exhibit HS-5 as compared to the Company's proposal.

Q. What changes does the Company propose for the Small General Service (SGS-10) rate?

A. For SGS customers, the Company is requesting an increase in the customer charge from \$14.50 and \$16.50 (TOU) to \$30.00.[35] The energy charges also are proposed to increase.[36] This non-demand class will be limited to customers with a maximum energy consumption of 12,000 kWh.

Q. Is the Company's increase in the customer charge for Small General Service customers (SGS-10) appropriate?

A. The unit cost information in Schedule G-6-1 indicates that customer costs for the SGS Class are \$29.74.[37]

Q. What changes does Staff recommend to the SGS rate?

A. For the pre-transition period Staff recommends the following modifications of the Company's proposal:

- The customer charge of \$30.00 as requested by the Company is appropriate.

- The revenue allocated to the SGS class should be collected first by an increase in the customer charge up to the level proposed by the Company, with the remainder (if

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[35] Jones Direct 43:10
[36] UNSE Schedule H-3, Page 1
[37] UNSE Response to STF 2.057, Line 23

any) recovered by increased energy charges on a proportional basis between blocks. Applying the revenue increase to the Customer Charge first will increase recovery of fixed charges and reduce the impact within the LFCR mechanism.

- The Company's proposal to move a customer to the new MGS rate "if the customer's consumption meets or exceeds 12,000 kWh in consecutive months" is vague as the number of months is not defined, nor has the impact been determined. Absent further information, Staff does not support this provision and suggests the Company address this issue in its rebuttal testimony.

Q. The existing RES and SGS rates are not Three-Part-TOU rates and therefore are not in accordance with the Staff's rate design plan. How would these rates transition?

A. Staff recommends that the Commission approve in this proceeding a mandatory transition to Three-Part-TOU rates for RES and SGS customers subject to a Company-filed transition plan.

The transition would not begin until the Company is able to provide each customer with at least three months of demand and TOU data from AMI meters. Transition would be done in phases of about one quarter of the class at each time. The transition could start as early as January 1, 2017, which would give the Company approximately six months to develop its customer education program and implement one or more means of providing data to customers before the transition begins. This transition would be complete by the end of 2017.

The Company would also need to provide data to these customers on an on-going basis in an easy to self-retrieve form such as a mobile application, website, or on the bill. The application or website would also provide tools and educational materials for the customer to demonstrate how to manage and reduce demand.

Q. What rates would be used for the transitioned customers?

A. Three-Part RES and SGS TOU rates would be designed to match the existing two-part rates approved at the conclusion of this case. The demand charge would not exceed 75 percent of the unit costs for distribution[38] to lessen the impact while customers learn to manage their demand. There would be no demand ratchet[39] to avoid penalizing customers for one-time demand excursions. Demand rates would apply only to On-Peak periods. There would be no change to the TOU periods in effect now.

Q. How would the transition affect the rates paid by RES and SGS customers?

A. There should be no customer class impact because the Three-Part TOU rates would be designed to match the pre-transition two part rates and recover the same class revenue requirements. However, under any transition between rates, those customers that are not similar to average customers within the class will see positive (lower bills) or negative (higher bills) impacts. This is why customer education and information is necessary.

Q. Would there be monitoring of the transition?

A. Yes. Revenue monitoring and customer complaint tracking on a class, phase and individual customer basis should be provided to Staff each quarter and filed in this docket.

[38] UNSE Schedule G-6-1, lines 19 and 20

[39] A demand ratchet stipulates that a customer's billing demand cannot be less than a stated percentage (sometimes as high as 100 percent) of maximum demand during a previous period (usually twelve months ending with the current month). Gas Rate Fundamentals (Fourth Edition), American Gas Association, 1987 page 170-171

Q. What would start each phase into transition?

A. The transition for the next phase would be determined after the preceding phase was on the three-part rate for at least four months. If the customer impact, education and information delivery was working well, then the next phase could be initiated.

Q. How would a phase be determined?

A. Staff recommends that the phases be selected based on energy consumption with the largest consumers to be first. These customers should have the greatest flexibility to manage their demand and consumption.

Q. Would residential DG customers be moved to the RES-01-Demand (or TOU) at the close of this case as requested by the Company?

A. No. Consistent with the long-term rate design plan, the actions taken behind the meter of any customer are not the sole determinant of which rate the customer must take. All DG customers would transition with their respective residential customer phase.

Q. What is the Company's proposal for a new Medium General Service ("MGS") rate?

A. The Company wants to establish a new MGS rate for existing Large General Service ("LGS") customers with demand between 20 kW and 750 kW.[40] This rate will have the same demand measurement and ratchet as the previous LGS class. The Company is requesting an increase in the customer charge from the $50.00 and $52.00 (TOU) (now charged to these customers presently on the existing LGS rate) to $100.00. Demand charges are proposed to increase from $12.81 to $13.05 per kW.[41] The Company is proposing that any customer that exceeds the 750 kW cap "for a billing month will be automatically moved in the subsequent month to

[40] Jones Direct 43:17 and 43:25
[41] UNSE Schedule H-3, Page 2

the new LGS rate class. The customer must remain there for at least 12 months without exceeding the 750 kW demand to qualify to move back to MGS."[42]

Q. Is the Company's proposal to create a new Medium General Service rate class and MGS rate schedule appropriate?

A. Yes. The present LGS rate includes customers with a wide range of demands and adding the MGS rate is appropriate.

Q. Is the Company's customer charge for MGS customers appropriate?

A. The unit cost information in Schedule G-6-1 indicates that customer costs for the Medium/Large General Service Class are $264.73.[43] Unfortunately, the unit costs were not differentiated between the MGS and LGS rate class.

Q. What changes does Staff recommend to the MGS rate?

A. Staff recommends the following modifications of the Company's proposal:

- The three-part rate design is appropriate as it retains the existing rate structure.

- The $100 customer charge requested by the Company may be appropriate in light of the mixed CCoSS for Medium/Large General Service. Staff requests that the Company differentiate Medium General Service customer costs from Large General Service in its rebuttal.

- The revenue allocated to the MGS rate should be collected first by an increase in the customer charge up to the level proposed by the Company, with the remainder (if

[42] Jones Direct 43:25
[43] UNSE Response to STF 2.057, Line 23

any) recovered by increased demand and energy charges. Applying the revenue increase to the Customer Charge first and then to demand charges will increase recovery of fixed charges and reduce the impact within the LFCR mechanism.

- The Company's proposal that "any customer exceeding the cap for a billing month will automatically be moved, in the subsequent month, to the new LGS rate class", is abrupt and too short a period to determine if the move is appropriate, nor has the impact been determined. Absent further information, Staff does not support this provision and suggests the Company address this issue in its rebuttal testimony.
- The Company should split the Medium/Large General Service cost of service class into two cost of service classes in its next rate case to verify the costs to be used in the respective rate designs.

Q. What changes does the Company propose for the Large General Service ("LGS") rate?

A. For LGS rate customers, the Company is requesting an increase in the customer charge from $50.00 and $52.00 to $300.00. Demand charges are proposed to increase from $12.81 to $12.96 per kW.[44] This class will have a minimum demand of 450 kW, and there will be no demand cap.[45] This class is now for customers served at less than 69 kV.[46]

Q. How can customers subject to the minimum demand of 450 kW be protected?

A. The Company has not detailed whether the new minimum demand of 450 kW will impact any customers and the extent of that impact.

[44] UNSE Schedule H-3, Page 2
[45] Jones Direct 44:4
[46] Jones Direct 44:12

Q. Is the Company's increase in the customer charge for LGS customers appropriate?

A. The unit cost information in Schedule G-6-1 indicates that customer costs for the Medium/Large General Service Class are $264.73.[47]

Q. What changes does Staff recommend to the LGS rate?

A. Staff recommends the following modifications of the Company's proposal:

- The three-part rate design is appropriate as it retains the existing rate structure.

- The $300 customer charge requested by the Company may be appropriate in light of the mixed CCoSS for Medium/Large General Service. Staff requests that the Company differentiate Medium General Service customer costs from Large General Service in its rebuttal.

- The revenue allocated to the LGS rate should be collected first by an increase in the customer charge up to the level proposed by the Company, with the remainder (if any) recovered by increased demand and energy charges. Applying the revenue increase to the Customer Charge first and then to demand charges will increase recovery of fixed charges and reduce the impact within the LFCR mechanism.

- The proposal to impose a minimum demand of 450 kW has not been supported in the Company's filing. Absent support indicating the number of customers affected and the extent of the impact, Staff does not support this provision and suggests the Company address this issue in its rebuttal testimony.

[47] UNSE Response to STF 2.057, Line 23

Q. What rate changes does the Company propose for the Large Power Service ("LPS") customer class?

A. For LPS rate customers, the Company is requesting no change in the customer charge of \$1,200.00.[48] Demand charges are proposed to decrease from \$17.00 to \$12.48 per kW.[49] This demand class will continue to have a minimum demand of 500 kW.[50] At present, LPS customers are subject to an 11-month 100 percent demand ratchet.[51]

Q. Is the Company's no change in the customer charge for Large Power Service customers appropriate?

A. The unit cost information in Schedule G-6-1 indicates that customer costs for the Large Power Service Class are \$2,149.58.[52]

Q. What changes does Staff recommend to the LPS rate?

A. Staff recommends the following modifications of the Company's proposal:

- The three-part rate design is appropriate as it retains the existing rate structure.

- The customer charge should be set at \$1,500 to move toward a cost based rate.

- The revenue allocated to the LPS rate should be collected first by an increase in the customer charge up to the level proposed here, with the remainder (if any) recovered by increased demand and then energy charges. Applying the revenue increase to the Customer Charge first and then to demand charges will increase recovery of fixed charges and reduce the impact within the LFCR mechanism.

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[48] Jones Direct 44:19
[49] UNSE Schedule H-3, Page 2
[50] Jones Direct 44:21
[51] Jones Direct 46:8
[52] UNSE Response to STF 2.057, Line 23

Q. Is the Company's proposal for TOU rates for schools appropriate?

A. The Company is proposing a new MGS-TOU-S rate that will replace the smaller SGS-TOU School rate, which has no customers. These rates are similar to the respective TOU rates.[53] However, the energy charges for the LGS-TOU-S rate appear to be slightly higher than the LGS-TOU rate with only a slight difference in the Summer On-Peak period. The Company has not provided enough information to render an opinion on these rates. Staff suggests the Company address this issue in its rebuttal testimony.

Q. What changes is the Company proposing for the Lighting Service rate?

A. The Company is proposing increases in the service charge and the per watt charge in order to raise the performance of this allegedly underperforming class.[54] The wattage charge does not define whether it is solely the lamp wattage or if a ballast load is included.[55] Staff suggests the Company address this issue in its rebuttal testimony.

Q. Does Staff agree with the rate changes that the Company has proposed for the Lighting Service rate?

A. No. There is very limited testimony supporting the increase, and Schedule G-1 indicates the Lighting class has a return of 3.94 percent compared to a total system return of 2.31 percent.[56] After the Company's proposed increase the class will have a return lower than the total system return.[57] Further clarification is required before a recommendation can be made. Staff suggests the Company address this issue in its rebuttal testimony.

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[53] Jones Direct 48:24
[54] Jones Direct 49:17
[55] Exhibit CAJ-4 Schedule LTG
[56] UNSE Schedule G-1, line 39
[57] UNSE Schedule G-2, line 37

Q. Is there some risk when significant rate design changes are made?

A. Yes. Rate design changes may have unintended results for "outlier" customers that do not fit neatly into their apparent customer class. This risk is increased when customer research is limited or has not been performed.

Staff recommends, as provided for in the previous TEP settlement (Docket No. E-01933A-12-0291) and detailed above, the Commission should keep the rate design portion of this rate case open for at least six months after the completion of the transition (or 18 months after the rate effective date), whichever is later, to account for unanticipated customer rate impacts that are determined to be inconsistent with the public interest.

CARES

Q. Please describe the Company's proposal for CARES?

A. The Company is proposing to change the CARES rate to a flat monthly $10 discount from the RES-01 rate and to eliminate the exclusion of CARES customers from the DSM surcharge.[58] Existing CARES customers will be frozen on the present configuration of a reduced Basic Service Charge and a declining discount on energy usage. The freezing of this rate is similar to the now frozen CARES-medical rate.[59]

Q. What is the value/cost of the CARES discounts?

A. The Company estimates the discounts totaled $581,326 during the Test Year.[60]

[58] Jones Direct 54:9 and 55:7
[59] Jones Direct 54:18 and 55:13
[60] Jones Direct 55:4

Q. Is eliminating the DSM exclusion appropriate?

A. Yes. This subset of customers should not be excluded from a surcharge for reasons extraneous to the surcharge, which is the case with the DSM surcharge. The exclusion creates additional bookkeeping problems for the surcharge and its reconciliation. This exclusion has been eliminated at the Company's affiliate TEP.[61]

Q. Does Staff support the CARES proposal?

A. In keeping with Staff's long-term plan for rate design, the Staff supports the Company's CARES proposal subject to a few concerns.

- The Company should "prove out" that the level of CARES discounts after changes in rates and the removal of the exclusion of the DSM surcharge is at or above the Test Year amount of $581,326. This proof can happen anytime or later during a post decision compliance filing if there is no settlement.

- The roster of CARES customers should be examined, and any existing CARES customer who would be better off (on an annual basis) on the flat monthly $10 discount should be moved to the new CARES RES-01 discount rate.

- The Company should develop a CARES provision that would apply to customers that are transitioned to the Three Part-TOU rate.

[61] Jones Direct 55:20

Interruptible Rates

Q. Please describe the Company's interruptible rate proposals?

A. The Company is proposing to introduce a new interruptible Rider R-12 and freeze the current Interruptible Power Service ("IPS") rate and also increase the rate above the level proposed for most LGS customers since the CCoSS shows them to be "highly subsidized".[62] In response to a Staff data request, the Company replied, "Customers on the IPS rate do not substantially differ in size or usage habits from the Large General Service customers. Therefore, they were included in the cost allocation process as if they were Large General Service customers."[63]

Q. Have the IPS customers experienced an interruption?

A. The Company notes, "[t]hey have not been interrupted in recent years and therefore provide no quantifiable benefit to the system." In the last case, the Company added a provision allowing for remote interruption and the Company alleges that this caused the number of IPS customers to drop from 39 to 29.[64]

Q. Has the Company provided enough information to verify the subsidization of IPS by other LGS customers?

A. No. Staff suggests that the Company address this issue in its rebuttal testimony.

Q. Please describe the Company's new interruptible proposal?

A. Rider R-12 provides for customers to consider on or after each March 15th the Company's Market Value Capacity Price ("MVCP") for the coming months May through September. The information supporting the MVCP will be available to Staff for review. Customers have

[62] Jones Direct 52:3
[63] UNSE Response to STF 2.112
[64] Jones Direct 52:19

until April 15th to nominate interruptible load and will receive Interruptible Credits ($/kW) for each of the five summer months.[65] This proposal is similar to the tariff provision recently approved for TEP.[66]

Q. Does Staff support this new interruptible proposal?

A. Yes. The Rider R-12 proposal is based on market reflective costs for each year and is subject to review by Staff. Customers retain the ability to evaluate the offer each year and consider the value compared to the customer's costs under the business conditions in place for that year and decide whether to participate. This concept provides significant flexibility for customers.

Q. Does the existing IPS rate serve a useful purpose?

A. Customers on the existing IPS rate have not been interrupted and may be receiving a subsidy. Staff recommends that this interruptible provision be eliminated at the end of the Company's next rate case. This will put IPS customers on notice of the change so they can prepare to deal with either standard rates or transfer to the new Rider R-12 interruptible provision.

Distributed Generation

Q. What is the Company's proposal for excess energy produced by distributed generation and fed back into the Company's system?

A. The Company has proposed a new net metering rider that allows customers with DG to sell excess energy production to the Company at the Renewable Credit Rate.[67] This proposal would apply to all customers who submitted a completed application after June 1, 2015, while

[65] Exhibit CAJ-3 Rider R-12 Sheet 712-1
[66] Jones Direct 53:18
[67] Dukes Direct 2:11

existing DG customers (and applications submitted before June 1, 2015) would stay on the current rider for up to 20 years from the date of approval.[68]

Q. Does the Company's proposal eliminate the banking option for new DG customers?

A. Yes. The Company proposes to pay for energy received with a monthly bill credit.[69]

Q. Is the Company proposing that all DG customers move to a three part rate?

A. Yes.[70] The proposed rates are (RES-01 Demand, RES-01 Demand TOU, SGS-10 Demand, and SGS-10 TOU).[71]

Q. How is the Renewable Credit Rate ("RCR") defined?

A. The Company proposes a RCR of 5.84 cents per kWh, which it argues is equivalent to the most recent utility scale renewable energy purchased power agreement connected to the distribution system of the Company's affiliate TEP. The project in question is due for completion in 2015.[72]

The Company indicates that it would file an annual RCR update similar to the existing Market Cost of Comparable Conventional Generation when it makes its annual REST filing based on the most recent comparable utility scale purchased power agreement for renewable energy connected to the Company's or TEP's distribution systems,[73] which are under a common balancing authority.[74]

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[68] Dukes Direct 4:12
[69] Dukes Direct 4:17 and Tilghman 8:11
[70] Dukes Direct 4:26 and 23:4
[71] Dukes Direct 24:3
[72] Tilghman Direct 7:9
[73] Tilghman Direct 8:4
[74] Tilghman Direct 7:22

Q. Is a utility scale photovoltaic facility a reasonable proxy for the value of energy provided by photovoltaic DG?

A. The Company argues that a utility scale photovoltaic facility is a reasonable proxy for photovoltaic DG because it has similar production characteristics (seasonality, time of day and response to weather). If the procurement of the utility scale energy is from one or more independent suppliers, then the resulting price is a reasonable estimate of the market value at that approximate location at that point in time and for the period of the Purchase Power Agreement ("PPA").

Excess energy from a photovoltaic DG installation is not entirely representative of a utility scale PV facility because the DG customer is providing the net output equal to the photovoltaic output less any energy consumed by the customer.

Q. Did your examination of the information provided by the Company raise any questions about the proposed 5.84 cents per kWh price?

A. Yes. The Company response to STF 2.038 is classified as competitively sensitive, and I have not included any specific items or values here. The original PPA was not provided, the Company only provided the 5th amendment and a series of exhibits.

The facility, which the Company characterizes as the "most recent utility scale renewable energy purchased power agreement," is not a standalone facility, but the second phase of a two-phase facility. The price paid for the first phase is above the proposed 5.84 cents/kWh RCR. It appears that the costs of interconnection, which are to be paid for by the Seller, may be included within the first phase's rate and are not mentioned in relation to the second phase's rate.

There is no mention of whether the Buyer or the Seller has the rights to the Renewable Energy Credits ("RECs") for the energy sold. Rider R-10 and Rider R-11 also do not mention RECs or which party will have title to them.[75] This is important as RECs have value, and it is not clear whether the Company is offering the RCR for energy alone or energy and the associated RECs.

The Seller is responsible for losses to the point of delivery and the Buyer (TEP) is responsible for losses incurred after the point of delivery. While the Company is an affiliate of TEP, the Seller's facility is not connected to the Company.

Q. Did the Company perform a system loss study?

A. Yes. The Company provided a loss study[76] (classified as competitively sensitive) that is based on identifying inputs (generation and purchased power) and outputs (retail and wholesale sales), and the remaining energy is considered losses. Since the Company still procures significant energy through power purchases and it appears that the power purchases are net of losses, then the losses in the study provided would appear to be understated. This concern is validated by the Company's email response.[77] Informally the Company indicated that Western Area Power Administration ("WAPA") uses a blanket 3 percent loss for its transmission of energy within its load research work.[78]

Q. How should the purchase price for excess DG energy be adjusted for losses?

A. Most of the energy the Company generates or purchases should be assumed to transit the WAPA system, the Company's transmission system, and for most customers the Company's distribution system. A portion of the energy consumed by a distribution customer is lost

[75] Exhibit CAJ-4
[76] UNSE Response to STF 2.062
[77] Email from Craig Jones dated 10/13/15 3:12 AM Item 4
[78] On-site load research interview on 9/8/15

from the point of generation to the ultimate customer. Since it is likely that energy is provided by a DG customer to nearby neighbors, losses should be added to the RCR. Based on the Company's loss study[79] plus the WAPA allowance, losses could be substantial.

Q. What other potential savings and costs are due to the existence of DG?

A. There may be savings in transmission charges; however, the Company has not addressed this issue. Other parties to this case may be able to add to the record in this area.

Some participants may consider savings from deferred or avoided distribution investment. The Company has identified a TEP substation[80] as a possible preferred location for the installation of solar generation along with supporting technologies. If DG can be shown to defer or eliminate required distribution investment, DG customers that provide the needed "support" should receive a locational adder to the RCR. Other parties to this case may be able to add to the record in this area.

Q. Does Staff have a recommendation as to how to determine the value of excess energy?

A. It is early in this proceeding and many interested parties have not yet filed their positions on the value of excess energy. Also, as Staff witness Thomas M. Broderick has detailed, Commission Docket No. E-00000J-14-0023, which is intended to examine the value and cost of DG, may provide useful information to the parties in this rate case. Therefore, for the time being, Staff does not propose any changes to the existing net metering tariff or waivers of the net metering rules but it may update its position in its Surrebuttal testimony or later at the hearing in this case. If ultimately the Commission continues to rely upon net metering, the migration to a three-part tariff will not pose any issues as the energy kWh charges in a three-part tariff and on a time-of-use basis would be used for net metering.

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[79] CONFIDENTIAL UNSE Response to STF 2.062
[80] UNSE Response to STF 2.034

Service Fee Changes

Q. Please describe the changes proposed by the Company to the UNSE Electric Statement of Charges?

A. The Company is not proposing increases to the following charges:

- Service Transfer Fee
- Customer Requested Meter Re-read
- Special Meter Reading Fee
- Returned Payment Fee
- Late Payment Finance Charge

The Company is proposing increases to the following charges:

- Service Establishment, Reestablishment or Reconnection of Service (regular business hours), along with a different and higher charge for after regular hours and weekends and holidays
- Service Reestablishment under other than usual operating procedures including Automated Meter Reading Opt-Out Set Up Fee
- Meter Test

The Company is requesting a new charge for Consumption History Request and Interval History Request on an hourly basis.[81]

Q. What did you find during your review of the cost support data for these charges?

A. In response to a Staff data request, the Company provided a worksheet detailing the underlying costs for each of these charges.[82] After Staff's review, a supplemental worksheet was provided. This revision lowered the charge for the Consumption History Request and Interval History Request to $60 per hour, which is reasonable based on the costs provided.

[81] Exhibit CAJ-3 Original Sheet 801 and Jones Direct 70:9
[82] UNSE Response to STF 2.077

Q. What other concerns do you have with the Consumption History Request and Interval History Request charge?

A. There appears to be some confusion as to when this charge will be applied. The Company states this charge will apply only after the first time a customer requests interval data, but this is not clear on the Statement of Charges.[83] Also, this charge should not apply if the Company develops a means to allow customers to look up or request their usage information online or through a mobile application that does not require the work of an employee. Finally, Staff recommends that this charge not apply for a period of six months after the mandatory transition of RES, SGS and MGS customers.

Q. Is the inclusion of Automated Meter Opt-Out Set-Up within the classification of Service Reestablishment under other than usual operating conditions appropriate?

A. No. The proposed charge of $196 for the Automated Meter Opt-Out Set-Up Fee has been set using a minimum 2 hours of an On Call Lineman. Changing the meter for an Opt-Out customer does not have to be done as a special after hours event and can be scheduled during normal working hours. Therefore, the charge should be $47 for Service Establishment, Reestablishment or Reconnection of Service under usual operating procedures During Regular Business Hours to reflect this situation.

Buy-Through

Q. Please describe the "Buy-Through" proposal submitted by the Company?

A. The "Buy-Through" was required to be introduced by the Company as a result of a settlement during the merger process,[84] but the Company does not support this tariff

[83] Jones Direct 70:9
[84] Jones Direct 56:3

change.[85] The Company indicates that the conceptual structure is similar to the "Buy-Through" provision in use at Arizona Public Service Company.[86]

The Company proposes that all revenue lost under this program, which it calls a "cost shift",[87] would be recouped from other customers through the LFCR mechanism.[88] This amount is significant and estimated by the Company at $331,200 annually in years two through four of the program.[89]

Q. What is the Staff position on the "Buy-Through"?

A. Because the Company is not supporting this concept, there is no record describing the benefits to non-participating customers. Staff looks forward to testimony in support of the "Buy-Through". Staff does not object to a "Buy-Through" mechanism if there are no adverse impacts and no costs to all other customers. Staff opposes recouping any allegedly lost Buy-Through revenue in the LFCR and likewise opposes any deferral of allegedly lost Buy-Through revenue.

AMI Opt-Out

Q. What is the AMI Opt-Out?

A. Some customers have raised concerns about the use of meters that transmit data wirelessly back to the Company. These customers wish to retain their existing mechanical meters, which would then require the Company to read the meter by travelling to the Opt-Out customer's premise, which raises the costs of serving these customers compared to all other customers.

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85 Jones Direct 56:8
86 UNSE Response to STF 2.115
87 Jones Direct 58:19
88 Jones Direct 59:1
89 UNSE Response to STF 2.118

Q. Is the retention of mechanical meters for Opt-Out customers appropriate?

A. No. If the Commission endorses Staff's rate design plan, all customers will need to have meters that record interval data in order to implement Three-Part TOU rates. Mechanical meters cannot provide the data required for, and the potential benefits of, new rate forms. Further, if Opt-Out customers could avoid demand metering, then other customers might opt out solely for rate design objections, thus raising the number of mechanical meters and the number of those meters that must be read by a visit to the customer's premise.

Q. Is there an alternative that deals with the concerns and provides the interval data for new rate forms?

A. This issue was raised informally with the Company and it suggested a solid-state meter with recording capabilities, which accumulates but does not transmit information.[90] The Company would read the interval data by visiting the customer's premise monthly.

Q. What is Staff's recommendation?

A. If a customer decides to Opt-Out, the Company should install a non-transmitting recording device and read that meter monthly. Because the number of Opt-Out customers is expected to be small and geographically dispersed, the costs of the monthly meter reading should be the Special Meter Reading Fee that requires a premise visit. The costs of the new meter installation should be recouped from the customer requesting this non-standard meter (at the $47 for Service Establishment, Reestablishment or Reconnection of Service under usual operating procedures During Regular Business Hours) along with the monthly reading costs (at the $26 Special Meter Reading Fee). Staff will monitor the number of special read customers to determine if the Special Meter Reading Fee remains appropriate as the number of customers using the Opt-Out develops.

[90] Email from Brenda Pries dated 11/23/15 at 11:30 AM

Economic Development

Q. Please describe the economic development program proposed by the Company?

A. The Company is proposing an Economic Development Rider R-13 ("EDR") for current or potential commercial or industrial customers that meet certain economic development criteria within the Company's service area. The EDR will be available to customers with a projected peak demand of 1,000 kW or more and a load factor of 75 percent or higher. Discounts would decline over a five-year period. New load would be limited to 50 MW.[91]

Q. What reasons did the Company provide as support for the EDR program?

A. The Company argues that its service territory has been slow to recover from the economic downturn post 2007 and that it has lost several of its largest customers in the past few years, resulting in lower sales over which fixed costs can be spread.[92]

Q. What are the specific qualifications to obtain the EDR?

A. The EDR qualifications are linked to existing Arizona state tax credit programs, which appear to be designed to create new in-state above median wage jobs with healthcare benefits.[93]

Q. What levels of discount are offered?

A. For economic development (requires the building of new facilities), the discount starts at 20 percent and declines to 2.5 percent. For economic redevelopment (occupying vacant facilities), the discount starts at 30 percent and declines to 5 percent.[94]

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[91] Dukes Direct 31:22
[92] Dukes Direct 30:15
[93] Dukes Direct 32:6
[94] Dukes Direct 32:17

Q. How will the discounts be recouped?

A. The Company's proposal did not address this issue. Staff explored this question in a data request. The Company responded that most of the revenues will reduce incremental revenues between rate cases, but the Company may request some form of consideration in future rate filings if the discounts extend into a new rate period, subject to full evaluation and Commission approval.[95]

Q. Will existing customers be protected from the impact of new capital expenditures?

A. The Company's proposal did not address this issue. Staff explored this question in a data request. The Company responded that the present rules and regulations approved by the Commission governing line extensions and new services would apply equally to these new customers or incremental loads.[96]

Q. At present the Commission is encouraging energy efficiency so isn't the EDR program the direct opposite because it will increase energy sales?

A. Conceptually, electric energy efficiency programs have not focused on limiting the increase in new customers but focused on increasing the efficiency of energy usage. Economic development rates can increase the number of employers, employees and maybe machinery and are expected to provide economic benefits within the utility's service territory. The Company's EDR program is geared towards the reuse of vacant facilities, which have some existing unused (or underused) electrical distribution capacity. Although EDR customers are proposed to be on a standard rate schedule with a discount, if the Commission is concerned about load growth, requirements could be added, such as using only time-of-use rates and/or the Rider R-12 interruptible service.

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[95] UNSE Response to STF 2.023
[96] UNSE Response to STF 2.024

Q. What is Staff's recommendation for the EDR?

A. The proposed EDR has limits and is biased towards existing facilities. The Company should address the potential impact of new energy requirements for the incremental load in its rebuttal. Assuming that the energy costs are not significant, then Staff supports this limited (volume and time) program to increase employment in the service territory. Staff's support does not extend to any request for recoupment of the lost incremental revenues absent a supporting record in some future proceeding.

LOST FIXED COST RECOVERY

Q. What purpose does the LFCR mechanism serve?

A. The LFCR mechanism, as approved by the Commission, serves to compensate the Company between rate cases for the revenue lost by the Company's compliance with established requirements for EE and DG.

Q. What is your experience with the LFCR mechanism in Arizona?

A. On behalf of Staff, I sponsored the LFCR mechanism in the Arizona Public Service ("APS") rate case (Docket No. E-01345A-11-0224), the TEP rate case (Docket No. E-01933A-12-0291) and the last UNSE rate case (Docket No. E-04204-12-0504).

Q. Please describe the Company's LFCR proposal in this proceeding.

A. The Company's LFCR proposal[97] is to change the established LFCR mechanism to increase the revenue recovered due to the effects of energy efficiency and distributed generation and to add a new category of recovery[98] due to the operation (if approved) of a "Buy-Through" provision (which the Company notably does not support)[99] added to the Company's tariff.

[97] Jones Direct 74:11
[98] Jones Direct 59:5
[99] Jones Direct 56:8

The Company also proposes to modify the LFCR mechanism as it appears to customers by removing the Fixed Cost Option[100] and presenting the charges on the bill as a single line item rather than its present split into EE and DG portions[101].

Q. What is the revenue impact of the Company's proposed changes to the LFCR mechanism?

A. The Company estimates the impact of the recovery of generation costs and 100 percent of the demand costs to be $573,000.[102] Although Staff's discovery request had asked for these two items separately, the Company has provided a combined amount.[103] The Company estimates that the expansion of the LFCR mechanism to include the recovery of revenue lost due to a "Buy-Through" provision in the tariff is $331,200 annually in years two through four.[104] If the Company's requested increases in the Basic Service Charge are implemented, then the impact of the LFCR is mitigated by an estimated $509,000.[105]

Q. What changes is the Company proposing that will affect the presentation on the customer's bill?

A. Presently, the utility is required to show the EE and DG components of the LFCR mechanism on the bill as two separate items. The Company is proposing to combine the two items (and I presume the new "Buy-Through" costs) into single line items.[106]

The Company is also asking for permission to no longer offer the Fixed Cost Option in the LFCR mechanism.

[100] Jones Direct 77:15
[101] Jones Direct 77:7
[102] Jones Direct 75:18
[103] UNSE Response to STF 2.121 and 2.119
[104] UNSE Response to STF 2.118
[105] UNSE Response to STF 2.119
[106] Jones Direct 77:7

Q. What portions of the Company's proposal to modify the LFCR mechanism do you recommend that the Commission accept?

A. I support the Company's proposal to remove the Fixed Cost Option from the LFCR because no customer has used that option at the Company[107] or at the Company's affiliate TEP.[108]

Q. What portions of the Company's proposal to modify the LFCR mechanism do you recommend that the Commission not accept?

A. The Commission should not accept the proposals that will increase the revenue impact on customers including:

- Allowing the Company to receive recovery for generation costs
- Increasing the recovery for distribution demand costs from 50 percent to 100 percent
- Increasing the cap on recovered costs allowed for each year from 1 percent to 2 percent
- Expanding the LFCR mechanism to include revenues lost from a "Buy-Through" provision to be established in the Company's tariff

Further, the Commission should not accept the change proposed by the Company to combine the EE and DG portions of the mechanism on the customer's bill as that provision was originally implemented by the Commission[109] and serves to highlight for the customer the relative impacts of EE and DG, which affect different customer subclasses. Also, adopting a single charge would conceal the recovery of "Buy-Through" costs from customers, if that proposal were accepted.

[107] Jones Direct 77:15
[108] Email from Craig Jones dated 9/21/15
[109] July 11, 2013, Open Meeting

Q. Why should the Commission reject including generation and purchased power in the LFCR mechanism?

A. The Company's purchased power program[110] appears to have a significant amount of flexibility that would allow the Company to adjust its purchases to match its short-term needs, and purchased power is fungible. Purchased power is not affected if energy is delivered to a new customer, an existing customer using slightly more energy, or sold off-system. Therefore, the Company has many opportunities to adjust its energy supply.

Q. What is the Company's forecast for sales?

A. The Company's load forecast shows a trend of increasing total numbers of customers[111] and the reference case (without the effects of EE and DG) shows increasing sales to retail customers.[112] The reference case for peak demand also shows increasing customer demand.[113]

Q. Could the proposed EDR and the Company's LFCR changes create a situation where some generation could be double collected?

A. Yes. The Company is proposing an economic development rate in this case that if successful would increase energy sales, peak demand and revenue. In an unusual twist, if the Company's proposal to include generation in the LFCR mechanism is approved, the Company could bill existing customers for the generation costs within the LFCR mechanism, redirect the generation (energy and capacity) to a new customer attracted by the proposed economic development rates and effectively double collect on that load.

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110 UNSE Response to STF 2.073
111 UNSE 2014 Integrated Resource Plan Chart 6 (page 39)
112 UNSE 2012 Integrated Resource Plan Chart 9 (page 43)
113 UNSE 2012 Integrated Resource Plan Chart 10 (page 44)

Q. Why should the Commission reject increasing from 50 percent to 100 percent the distribution demand component in the LFCR mechanism?

A. Distribution costs are not as fungible and some distribution assets cannot serve other customers within the short term. Therefore, a reduction in per customer sales may result in a shortfall in revenues to cover distribution fixed costs. The LFCR adopted by the Commission provides a mechanism to recapture the portion of distribution costs that are collected on a volumetric (per kWh) basis. Some of the Company's rate schedules collect distribution costs using demand charges, which will remain constant or change slower than a straight volumetric rate.

Q. Why should the Commission reject increasing from 1 percent to 2 percent the cap in the LFCR mechanism?

A. The existing LFCR mechanism has not reached the 1 percent cap.[114] I also expect the Commission's treatment of DG to evolve at the end of this case and that would also mitigate the need to raise the cap. If the Commission does not accept the Company's proposed changes to the LFCR, then the increase in the cap is not necessary.

Q. Should the Commission reject including the costs of a Buy-Through" provision in the tariff in the LFCR mechanism?

A. The "Buy-Through" was required to be introduced by the Company as a result of a settlement during the merger process,[115] and the Company does not support this tariff change. It appears that this provision would allow one or more large customers to take advantage of lower costs within the energy supply market, and the Company is asking all other customers to absorb its potential lost revenues in years two through four of the provision. Effectively, the Company's request to include "Buy-Through" within the LFCR

[114] Jones Direct 77:20
[115] Jones Direct 56:3

mechanism forces all customers to subsidize the potential savings for a small class of large, sophisticated customers. This attempt at cross subsidization should be rejected.

Q. What changes does Staff recommend for the LFCR mechanism?

A. As highlighted in the testimony of Staff witness Thomas M. Broderick, Staff will recommend in the Company's next rate case that the DG portion of the LFCR be eliminated. In this case Staff recommends that the DG portion of the LFCR apply only to lost fixed costs from the end of the Test Year until the rate effective date. Staff's long-term rate design plan recognizes that DG is no different than other customer initiatives to control their costs. Further, Staff has recommended increases in customer and demand charges for existing rates along with the mandatory transition to Three Part-TOU rates for Residential and Small General Service customers, all of which reduce the need for the LFCR mechanism by increasing the recovery of fixed costs.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Testimony - Howard Solganick

Arizona Corporation Commission
Case – UNS Electric Docket No. E-04204A-12-0504 (June 2013 and July 2013)
Client - Staff of the Arizona Corporation Commission
Scope - Testimony covered revenue decoupling, cost of service, revenue allocation, rate design and other related issues.

Case – Tucson Electric Power Company Docket No. E-01933A-12-0291 (December 2012 and January 2013)
Client - Staff of the Arizona Corporation Commission
Scope - Testimony covered revenue decoupling, cost of service, revenue allocation, rate design and other related issues.

Case – Arizona Public Service Company Docket No. E-01345A-11-0224 (November and December 2011)
Client - Staff of the Arizona Corporation Commission
Scope - Testimony covered revenue decoupling, cost of service, revenue allocation, rate design and other related issues.

Public Service Commission of Delaware
Case - Delmarva Power & Light Company Docket No. 10-237 (October 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and miscellaneous charges.

Case - Delmarva Power & Light Company Docket No. 09-414 (February 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and weather normalization.

Case - Delmarva Power & Light Company Docket No. 09-277T (November 2009)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered an analysis of a straight fixed variable rate design for small gas customers and implementation issues.

Case - Delmarva Power & Light Company Docket No. 06-284 (January 2007)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization or normalization.

Georgia Public Service Commission
Case – Atlanta Gas Light Company Docket No. 31647 (August 2010)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered revenue forecast, cost of service, revenue allocation, rate design and other related issues.

Case – Atmos Energy Corporation Docket No. 27163 (July 2008)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission

Scope - Testimony covered rate design and other related issues.

Jamaica (West Indies) Office of Utility Regulation
Case - Electricity Appeals Tribunal (August 2007)
Client - Jamaica Public Service Company, Ltd.
Scope - "Witness Statement" on behalf of the Jamaica Public Service Company Limited. This Statement covered issues relating to recovery of expenses incurred due to Hurricane Ivan.

Maine Public Utilities Commission
Case - Northern Utilities, Accelerated Cast Iron Replacement Program Docket No. 2005-813 (2005)
Client - Public Advocate of the State of Maine
Scope - Testimony covered an analysis of the program's economics and implementation.

Public Service Commission of Maryland
Case - Chesapeake Utilities Corporation Case No. 9062 (August 2006)
Client - Office of the Maryland People's Counsel
Scope - Testimony covered cost of service, rate design and other related issues.

Case - Baltimore Gas & Electric's (1993)
Client - As president of the Mid Atlantic Independent Power Producers
Scope - Testimony covered BG&E's capacity procurement plans.

Michigan Public Service Commission
Case - Consumers Energy Company Case No. U-15245 (November 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered cost of service, rate design and revenue allocation.

Case - Consumers Energy Company Case No. U-15190 (July 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy's gas revenue decoupling proposal.

Case - Consumers Energy Company Case No. U-15001 (June 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy and the MCV Partnership.

Case - Consumers Energy Company Case No. U-14981 (September 2006)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues relating to the sale of Consumers interest in the Midland Cogeneration Venture.

Case - Consumers Energy Company Case No. U-14347 (June 2005)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope – Testimony covered cost of service and revenue allocation.

Missouri Public Service Commission
Case – AmerenUE Storm Adequacy Review (July 2008)
Client – KEMA/AmerenUE
Scope – Oral testimony covered KEMA's review of AmerenUE's system major storm restoration efforts.

Case – Veolia Energy Kansas City, Inc. File No. HR-2011-0241 (September 2011)
Client – City of Kansas City, Missouri
Scope – Testimony covered various aspects of the Company's tariff provisions and the impact on the City of Kansas City.

New Jersey Board of Public Utilities
Case - Cogeneration and Alternate Energy Docket # 8010-687 (1981)
Case - PURPA Rate Design and Lifeline Docket # 8010-687 (1981)
Case - Atlantic Electric Rate Case - Phases I & II Docket # 822-116 (1982)
Case - Power Supply Contract Litigation – Wilmington Thermal Systems Docket # 2755-89 (1989)
Case - NJBPU Atlantic Electric Rate Case - Phase II (1980-81) Docket # 7911-951 (Before the Commissioners of the New Jersey Board of Public Utilities)
Client - Employer was Atlantic City Electric Company.
Scope - The cases listed above covered load forecasting, capacity planning, load research, cost of service, rate design and power procurement.

Public Utilities Commission of Ohio
Case - The Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company Case 07-551-EL-AIR (January 2008)
Client - Ohio Schools Council
Scope - Testimony covers issues related to rate treatment of schools.

Case - The Application of the Columbus Southern Power Company 08-917-EL-SSO and the Ohio Power Company Case 08-918-EL-SSO (October 2008)
Client - Ohio Hospital Association
Scope - Testimony covers issues related to rates for net metering and alternate feed service and related treatment of hospitals.

Pennsylvania Public Utilities Commission
Case - York Water Company Docket No. R-00061322 (July 2006)
Client - Pennsylvania Office of Consumer Advocate
Subject - Testimony covered cost of service, rate design and other related issues, also supported the settlement process.

Case – Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2010)
Client – Municipal Sewer Group
Subject - Testimony covered capacity planning, construction, treatment of future load and associated revenue, cost of service, rate design, capacity fee and other related issues.

Case – Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2008)
Client – Municipal Sewer Group
Subject - Testimony covered cost of service, rate design, capacity fee and other related issues, also supported the settlement process.

Public Utilities Commission of Texas
Case – Determination of Hurricane Restoration Costs Docket No. 36918 (April 2009)
Client – CenterPoint Energy Houston Electric, LLC
Subject – Testimony covered the reasonableness of the client's Hurricane Ike restoration process for an outage covering over two million customers and a restoration period of 18 days

Exhibit HS-2

		A	B	C	D	E	F	G	H	I	J	K	L	M
			2014 CCoSS					2012 CCoSS				% Increase 2012 to 2014		
LINE	CCoSS Comparisons	Total UNS	Residential		SGS		Total UNS	Residential		SGS		Total UNS	Residential	SGS
			$	%	$	%		$	%	$	%			
1	Generation													
2	Tot Prod Plant	173,860,268	105,138,005	60.5%	14,956,558	8.6%	93,861,601	50,033,745	53.3%	6,039,021	6.4%	85.2%	110.1%	147.7%
3	Accum Depr	37,652,975	22,769,772	60.5%	3,239,147	8.6%	13,115,049	6,991,091	53.3%	843,817	6.4%	187.1%	225.7%	283.9%
4	Net Plant	136,207,293	82,368,233	60.5%	11,717,411	8.6%	80,746,552	43,042,654	53.3%	5,195,204	6.4%	68.7%	91.4%	125.5%
5														
6	Energy													
7	Power Generation Fuel	5,543,690	2,876,726	51.9%	412,514	7.4%	3,583,181	1,774,736	49.5%	218,956	6.1%	54.7%	62.1%	88.4%
8	Other Power Supply Expense	62,964,670	32,673,564	51.9%	4,685,296	7.4%	77,621,936	37,795,957	48.7%	4,743,210	6.1%	-18.9%	-13.6%	-1.2%
9	Subtotal	68,508,360	35,550,290	51.9%	5,097,810	7.4%	81,205,117	39,570,693	48.7%	4,962,166	6.1%	-15.6%	-10.2%	2.7%
10														
11	Distribution													
12	Distribution Plant	350,880,250	221,990,904	63.3%	35,589,734	10.1%	325,339,574	169,946,505	52.2%	25,634,537	7.9%	7.9%	30.6%	38.8%
13	Accum Depr	203,151,309	131,179,705	64.6%	17,260,152	8.5%	176,552,638	91,407,447	51.8%	13,308,571	7.5%	15.1%	43.5%	29.7%
14	Net Plant	147,728,941	90,811,199	61.5%	18,329,582	12.4%	148,786,936	78,539,058	52.8%	12,325,966	8.3%	-0.7%	15.6%	48.7%
15														
16	Transmission by Others													
17	PPFAC Eligible	9,014,026	4,677,549	51.9%	670,747	7.4%	8,853,006	4,310,738	48.7%	540,977	6.1%	1.8%	8.5%	24.0%
18	Non PPFAC Eligible	14,531,456	8,787,564	60.5%	1,250,088	8.6%	10,279,126	5,479,378	53.3%	661,355	6.4%	41.4%	60.4%	89.0%
19	Subtotal	23,545,482	13,465,113	57.2%	1,920,835	8.2%	19,132,132	9,790,116	51.2%	1,202,332	6.3%	23.1%	37.5%	59.8%

Exhibit HS-3

LINE	CCoSS Comparisons	A Total	B Residential	C Small General Service	D Medium/Large General Service	E Large General Service	F Large Power Service	G Large Power Service	H Mining	I Lighting
	2012									
1	Total Ratebase	$216,574,773	$114,992,540	$13,819,293		$51,716,825	$18,071,308		$16,834,066	$1,140,741
2	% of Ratebase		53.1%	6.4%		23.9%	8.3%		7.8%	0.5%
3										
4	Total Electric Revenue from Sales	$162,190,518	$80,572,595	$11,537,036		$47,795,940	$14,754,841		$6,914,746	$615,360
5	% of Electric Sales		49.7%	7.1%		29.5%	9.1%		4.3%	0.4%
6										
7	Total Operating Expenses	$149,373,340	$76,923,966	$10,619,009		$38,227,069	$13,953,652		$9,058,995	$590,649
8	% of Operating Expenses		51.5%	7.1%		25.6%	9.3%		6.1%	0.4%
9										
10	Operating Income	$12,817,178	$3,648,629	$918,027		$9,568,871	$801,189		-$2,144,249	$24,711
11										
12	Rate of Return	5.92%	3.17%	6.64%		18.50%	4.43%		-12.74%	2.17%
13	UROR		0.536	1.122		3.126	0.749		-2.152	0.366
14										
15	kWh Sales	1,818,398,842	848,675,174	96,989,850		513,288,747	223,497,643		133,074,196	2,673,232
16	% of Sales		46.7%	5.3%		28.2%	12.3%		7.3%	0.1%
17										
18	Test Year UNAdjusted Customers	91,507	79,493	7,962		1,884	21		2	2,144
19										
20										
21	**2014**									
22	Total Ratebase	$272,013,129	$166,482,331	$27,414,831	$70,946,559			$5,737,904		$1,431,504
23	% of Ratebase		61.2%	10.1%	26.1%			2.1%		0.5%
24										
25	Total Electric Revenue from Sales	$147,176,645	$73,653,026	$11,905,151	$53,699,953			$7,375,505		$543,010
26	% of Electric Sales		50.0%	8.1%	36.5%			5.0%		0.4%
27										
28	Total Operating Expenses	$140,891,931	$80,118,247	$12,183,739	$42,331,725			$5,771,597		$486,623
29	% of Operating Expenses		56.9%	8.6%	30.0%			4.1%		0.3%
30										
31	Operating Income	$6,284,714	-$6,465,221	-$278,588	$11,368,228			$1,603,908		$56,387
32										
33	Rate of Return	2.31%	-3.88%	-1.02%	16.02%			27.95%		3.94%
34	UROR		-1.681	-0.440	6.935			12.098		1.705
35										
36	kWh Sales	1,600,809,166	823,953,185	118,683,796	562,579,661			92,765,274		2,827,250
37	% of Sales		51.5%	7.4%	35.1%			5.8%		0.2%
38										
39	Test Year Adjusted Customers	95,144	82,607	8,758	1,387			4		2,388
40										
41										
42	**2014 vs 2012**									
43	Increase in Class Ratebase	25.6%	44.8%	98.4%						25.5%
44										
45	Increase in Electric Revenue	-9.3%	-8.6%	3.2%						-11.8%
46										
47	Increase in Operating Expenses	-5.68%	4.15%	14.74%						-17.61%
48										
49	Increase in kWh Sales	-12.0%	-2.9%	22.4%						5.8%
50										
51	Increase in Customers	4.0%	3.9%	10.0%						11.4%

Exhibit HS-4

LINE		TOTAL (A)	RESIDENTIAL SERVICE (B)	SMALL GENERAL (C)	MEDIUM/LARGE GENERAL (E)	LARGE POWER (F)	LIGHTING (H)
1	**75% of RES SGS to UROR = 1.00**						
2	Incremental Revenue	$18,128,000	$15,844,500	$1,992,750	$253,386	$34,802	$2,562
3	Rate of Return on Rate Base	6.92%	3.75%	4.49%	13.97%	24.22%	3.20%
4	UROR	1.00	0.54	0.65	2.02	3.50	0.46
5	% Incr compared to Revenue From Present Sales	12.32%	21.51%	16.74%	0.47%	0.47%	0.47%
6	% of the Total Increase	100.0%	87.4%	11.0%	1.4%	0.2%	0.0%
7							
8							
9	**67.7% of RES SGS to UROR = 1.00**						
10	Incremental Revenue	$18,128,000	$14,084,000	$1,771,333	$1,980,609	$272,030	$20,028
11	Rate of Return on Rate Base	6.92%	2.69%	3.69%	16.41%	28.35%	4.42%
12	UROR	1.00	0.39	0.53	2.37	4.10	0.64
13	% Incr compared to Revenue From Present Sales	12.32%	19.12%	14.88%	3.69%	3.69%	3.69%
14	% of the Total Increase	100.0%	77.7%	9.8%	10.9%	1.5%	0.1%
15							
16							
17	**60% of RES SGS to UROR = 1.00**						
18	Incremental Revenue	$18,128,000	$12,675,600	$1,594,200	$3,362,388	$461,812	$34,000
19	Rate of Return on Rate Base	6.92%	1.84%	3.04%	18.36%	31.66%	5.40%
20	UROR	1.00	0.27	0.44	2.65	4.58	0.78
21	% Incr compared to Revenue From Present Sales	12.32%	17.21%	13.39%	6.26%	6.26%	6.26%
22	% of the Total Increase	100.0%	69.9%	8.8%	18.5%	2.5%	0.2%
23							
24							
25	**50% of RES SGS to UROR = 1.00**						
26	Incremental Revenue	$18,128,000	$10,563,000	$1,328,500	$5,435,055	$746,486	$54,959
27	Rate of Return on Rate Base	6.92%	0.57%	2.07%	21.28%	36.62%	6.86%
28	UROR	1.00	0.08	0.30	3.08	5.29	0.99
29	% Incr compared to Revenue From Present Sales	12.32%	14.34%	11.16%	10.12%	10.12%	10.12%
30	% of the Total Increase	100.0%	58.3%	7.3%	30.0%	4.1%	0.3%
31							
32							
33	**All UROR equals 1.00**						
34	Incremental Revenue	$18,128,000	$21,126,000	$2,657,000	-$4,752,900	-$957,900	$55,800
35	Rate of Return on Rate Base	6.92%	6.92%	6.92%	6.92%	6.92%	6.92%
36	UROR	1.00	1.00	1.00	1.00	1.00	1.00
37	% Incr compared to Revenue From Present Sales	12.32%	28.68%	22.32%	-8.85%	-12.99%	10.28%
38	% of the Total Increase	100.0%	116.5%	14.7%	-26.2%	-5.3%	0.3%
39							
40							
41	**Equal Percentage**						
42	Incremental Revenue	$18,128,000	$9,071,970	$1,466,378	$6,614,315	$908,454	$66,883
43	Rate of Return on Rate Base	6.92%	-0.32%	2.57%	22.94%	39.44%	7.69%
44	UROR	1.00	-0.05	0.37	3.32	5.70	1.11
45	% Incr compared to Revenue From Present Sales	12.32%	12.32%	12.32%	12.32%	12.32%	12.32%
46	% of the Total Increase	100.0%	50.0%	8.1%	36.5%	5.0%	0.4%
47							
48							
49	**$18.128 million spread by UNS allocation**						
50	Incremental Revenue	$18,128,000	$16,524,739	$2,141,763	$21,178	-$620,445	$60,765
51	Rate of Return on Rate Base	6.92%	4.15%	5.04%	13.65%	12.80%	7.27%
52	UROR	1.00	0.60	0.73	1.97	1.85	1.05
53	% Incr compared to Revenue From Present Sales	12.32%	22.44%	17.99%	0.04%	-8.41%	11.19%
54	% of the Total Increase	100.0%	91.2%	11.8%	0.1%	-3.4%	0.3%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

Exhibit HS-5

RESIDENTIAL SERVICE

BILL IMPACTS CURRENT RATES

	Total kWh	Delivery (kWh)			Customer Charge	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill
		0-400	401-1,000	1,000+	$10.00	$0.01930	$0.03435	$0.03850	$0.001140	$0.064510	-$0.002139	
Xsmall	111	111	0	0	$10.00	$2.14	$0.00	$0.00	$0.13	$7.16	-$0.24	$19.19
Small	330	330	0	0	$10.00	$6.37	$0.00	$0.00	$0.38	$21.29	-$0.71	$37.33
Medium	664	400	264	0	$10.00	$7.72	$9.07	$0.00	$0.76	$42.83	-$1.42	$68.96
Large	1,144	400	600	144	$10.00	$7.72	$20.61	$5.54	$1.30	$73.80	-$2.45	$116.53
Xlarge	2,162	400	600	1,162	$10.00	$7.72	$20.61	$44.74	$2.46	$139.47	-$4.63	$220.37
Mean	830	400	430	0	$10.00	$7.72	$14.75	$0.00	$0.95	$53.51	-$1.77	$85.16
Sum	983	400	583	0	$10.00	$7.72	$20.04	$0.00	$1.12	$63.43	-$2.10	$100.20
Win	669	400	269	0	$10.00	$7.72	$9.25	$0.00	$0.76	$43.18	-$1.43	$69.48
Annual												$1,018.12

BILL IMPACTS - STAFF PROPOSED RATES

	Total kWh	Delivery (kWh)			Customer Charge	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
		0-400	401-1,000	1,000+	$15.00	$0.02638	$0.04143	$0.04558	$0.000000	$0.053288	$0.000000			
		400	600	1000										
Xsmall	111	111	0	0	$15.00	$2.93	$0.00	$0.00	$0.00	$5.91	$0.00	$23.84	$4.64	24.2%
Small	330	330	0	0	$15.00	$8.71	$0.00	$0.00	$0.00	$17.59	$0.00	$41.30	$3.96	10.6%
Medium	664	400	264	0	$15.00	$10.55	$10.94	$0.00	$0.00	$35.38	$0.00	$71.87	$2.91	4.2%
Large	1,144	400	600	144	$15.00	$10.55	$24.86	$6.56	$0.00	$60.96	$0.00	$117.94	$1.41	1.2%
Xlarge	2,162	400	600	1,162	$15.00	$10.55	$24.86	$52.97	$0.00	$115.21	$0.00	$218.59	-$1.78	-0.8%
Mean	830	400	430	0	$15.00	$10.55	$17.80	$0.00	$0.00	$44.20	$0.00	$87.55	$2.39	2.8%
Sum	983	400	583	0	$15.00	$10.55	$24.17	$0.00	$0.00	$52.40	$0.00	$102.12	$1.92	1.9%
Win	669	400	269	0	$15.00	$10.55	$11.16	$0.00	$0.00	$35.67	$0.00	$72.39	$2.90	4.2%
Annual												$1,047.06	$28.94	2.8%

BILL IMPACTS - UNS PROPOSED RATES

	Total kWh	Delivery (kWh)			Customer Charge	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
		0-400	401-1,000	1,000+	$20.00	$0.03081	$0.05081	$0.05081	$0.000000	$0.049260	$0.000000			
		400	600	1000										
Xsmall	111	111	0	0	$20.00	$3.42	$0.00	$0.00	$0.00	$5.47	$0.00	$28.89	$9.70	50.5%
Small	330	330	0	0	$20.00	$10.17	$0.00	$0.00	$0.00	$16.26	$0.00	$46.43	$9.09	24.4%
Medium	664	400	264	0	$20.00	$12.32	$13.41	$0.00	$0.00	$32.71	$0.00	$78.45	$9.49	13.8%
Large	1,144	400	600	144	$20.00	$12.32	$30.49	$7.32	$0.00	$56.35	$0.00	$126.48	$9.95	8.5%
Xlarge	2,162	400	600	1,162	$20.00	$12.32	$30.49	$59.04	$0.00	$106.50	$0.00	$228.35	$7.98	3.6%
Mean	830	400	430	0	$20.00	$12.32	$21.82	$0.00	$0.00	$40.86	$0.00	$95.01	$9.85	11.6%
Sum	983	400	583	0	$20.00	$12.32	$29.64	$0.00	$0.00	$48.44	$0.00	$110.40	$10.20	10.2%
Win	669	400	269	0	$20.00	$12.32	$13.69	$0.00	$0.00	$32.98	$0.00	$78.99	$9.51	13.7%
Annual												$1,136.37	$118.26	11.6%

EXHIBIT
S-6
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
Commissioner
ANDY TOBIN
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. 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 UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS	DOCKET NO. E-04204A-15-0142

SURREBUTTAL TESTIMONY

OF

HOWARD SOLGANICK

FOR THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2016

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EXECUTIVE SUMMARY
UNS ELECTRIC CORPORATION
DOCKET NO. E-04204A-15-0142

Mr. Solganick's surrebuttal testimony reviews the Company's revenue allocation proposal, compares it to Staff's recommendation and discusses the relationship between Staff's recommendation and the protections envisioned during the transition to three-part TOU rates recommended by the Staff.

The testimony also discusses Staff's recommended rate design and the relationship to the protections envisioned during the transition to three-part TOU rates recommended by the Staff.

The testimony also discusses CARES, Buy-Through and the LFCR proposal by the Company and Staff's arguments against that proposal.

INTRODUCTION

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

A. My name is Howard Solganick. I am a Principal at Energy Tactics & Services, Inc. My business address is 810 Persimmon Lane, Langhorne, Pennsylvania 19047. I am performing this assignment under subcontract to Blue Ridge Consulting Services, Inc. ("Blue Ridge").

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Utilities Division Staff ("Staff") of the Arizona Corporation Commission ("Commission").

Q. Have you previously submitted testimony in regulatory proceedings?

A. Yes. I have testified and/or presented testimony (summarized in Exhibit HS-1) before the following regulatory bodies:

- Arizona Corporation Commission
- Delaware Public Service Commission
- Georgia Public Service Commission
- Jamaica (West Indies) Electricity Appeals Tribunal
- Maine Public Utilities Commission
- Maryland Public Service Commission
- Michigan Public Service Commission
- Missouri Public Service Commission
- New Jersey Board of Public Utilities
- Public Utilities Commission of Ohio
- Pennsylvania Public Utility Commission
- Public Utility Commission of Texas

Q. Have you previously submitted testimony in this proceeding?

A. Yes. I previously provided direct testimony relating to the engineering analysis of the UNS Electric, Inc.'s ("UNSE" or "Company") rate base items, service reliability, and planning process on November 6, 2015, and cost of service, revenue allocation, rate design, and the Lost Fixed Cost Recovery mechanism ("LFCR") on December 9, 2015. My initial testimony in this case includes a summary of my background, qualifications, and experience.

Q. What is the purpose of your surrebuttal testimony?

A. My testimony provides a portion of Staff's response to rebuttal testimony filed by the Company along with direct testimony filed by some of the interveners.

SURREBUTTAL TESTIMONY

Q. Please summarize Staff's positions.

A. Staff recommended that rates should be based on costs and recognize the concepts of customer, demand and energy including time-of-use ("TOU"). When changes are made, gradualism should be recognized. This long-term rate design plan was placed into the context of evolving metering and customer information capabilities.

Staff recommended a revenue allocation among the customer classes based on moving all classes to cost of service but recognizing that gradualism is necessary due to the effects of a new production cost methodology and the Company's inclusion into rate base of its portion of the new Gila River Unit #3.

Staff recommended, consistent with the long-term rate design plan, the mandatory transition of residential and small general service rates to Three Part-TOU rates.

Staff highlighted that, due to the changes proposed, the Commission should keep the rate design portion of the rate case open to resolve significant unanticipated customer rate impacts.

Staff recommended that the level of the CARES discount not be reduced and that a CARES provision for the new Three Part-TOU rate should be developed.

Staff did not propose changes to the existing net metering tariff or waivers of the net metering rules in its December 9th testimony.

Q. What was Staff's revenue allocation proposal?

A. Staff recommended a revenue allocation that moved all classes gradually toward parity of return over this and the next rate case. Staff also recognized that the purchase of a combined cycle generating unit provides benefits to all customers during many hours of the year and, thus, it would be inappropriate to reduce rates for any customer class.

In the Company's filing it proposed a change in cost allocation methodology from Peaks and Average to Average and Excess.[1] The Company's proposed change reduced the class rate of return for the Residential, Small General Service and Lighting classes and raised the class rate of return for the Medium/Large General Service and Large Power Service classes.[2]

Staff's revenue allocation proposal is detailed in Exhibit HS-4 (previously submitted) and suggested that the Residential class receive 58.3 percent of the total increase ($10.5 million). This revenue increase of 14.3 percent for the Residential class and 11.16 percent for the Small

[1] Jones Direct 25:3
[2] Jones Direct 25:11

General Service class contrasts with a proposed 10.1 percent increase for all other classes.[3] The effect of Staff's recommended revenue allocation was intended to move to cost-based rates in this and the next rate case while providing protection during the transition to Three-Part TOU rates. Staff's recommended revenue allocation also acts to buffer the Residential, Small General Service and Lighting classes from the full effects of the Company's proposed change in cost allocation methodology.

Q. What revenue allocation does the Company propose in its rebuttal testimony?

A. While the Company states "... the Company is willing to adjust the allocation of revenue between the rate classes using Staff's suggestion as a guide,"[4] the Company's proposed increase for the Residential class is $15.9 million or 86 percent of the proposed $18.4 million increase.[5]

Q. What is the impact of the Company's new revenue allocation proposal?

A. The Company's new revenue allocation proposal is only a small decrease from its original proposal to assign over 91 percent of the increase to residential customers, almost 12 percent to small general service customers and decrease rates for large power customers and have rates even for medium and large service customers.[6] While the Company characterized its rebuttal revenue allocation as using Staff's suggestion as a guide, the Company has failed to remember that its change in cost allocation methodology, the purchase of Gila River Power Plant Unit #3 and other actions should be recognized and the affected classes see the temporary protection of gradualism.

[3] Exhibit HS-4 line 29
[4] Jones Rebuttal 2:26
[5] Exhibit CAJ-R-1
[6] Exhibit HS-4 lines 50, 54

Even under the Company's latest revenue allocation proposal it still will take two cases (the present and the next one) to move to cost-based rates. Further, the Company's proposed revenue allocation has not recognized the disproportionate impacts between the present Class Cost of Service Study ("CCoSS") and the prior one.[7]

The impact of the Company's use of Staff's suggestion as a guide can be easily seen by comparing the original Schedule G-2 and the Company's revised Schedule G-2[8] for the Large Power Service class' Proposed Sales Revenue (line 20) which moved from $6.604 million (original filing) to $6.777 million, an increase of less than 3 percent, while the Residential class moved from $94.209 to $94.098, a decrease of less than 0.2 percent. Under either Company proposal, the difference is more pronounced when Base Revenues Present Rates[9] are $7.376 million for Large Power Service resulting in a significant decrease (8.1 percent) and $73.653 million for Residential resulting in a significant increase (27.7 percent). NOTE: The Large Power Service class was used for this comparison because it retains the same number of customers and kWh sales while the Medium/Large General Service class is subject to a rate redesign.

Q. Why is the magnitude of the Residential increase important outside of the issue of revenue allocation?

A. Staff has always been cognizant of the impact of a rate design change both on a class level and the individual customer impact. That is why Staff has worked with the Company to analyze the impact of Staff's proposed rate design across a range of usage and supports the proposed 15 percent load factor floor. However, the Company's additional Residential class revenue allocation is layered on top of the rate design change. While it may not have been

[7] Solganick Direct 19:19
[8] UDR 3.1
[9] UNS Schedule G-1, line 20

apparent to the Company, Staff's suggested revenue allocation is part of the protection that Staff recommends as part of its rate design.

Q. Please describe Staff's rate design recommendation?

A. Staff has recommended the mandatory transition of all Residential and Small General Service customers from the present two-part rates to Three-Part TOU rates which offer all customers more opportunities to react to clearer costs and control their bills. Staff conditioned its recommendation on the requirement that the Company would develop and implement a transition plan that offers Residential and Small General Service customers both information AND education BEFORE the transition takes place.

Q. Where will the customer information come from?

A. The Company expects to complete its conversion to advanced metering capable of supporting three-part rates by the end of 2016[10] and has committed to providing consumption information to customers before the transition.[11] Customers will have a view into how and when they use electricity before the transition begins.

Q. How will customers know how to react to Three-Part TOU rates and decide if they wish to change the amount of energy they use and when they use it?

A. The Company has committed to an education program to inform customers of the impacts and benefits of the new rate design before the transition begins.[12] While the parties are still defining what information and education will be provided, Staff notes that the Company is planning web portal capabilities that will allow customers to access historical energy and demand interval data in multiple formats with about a one-day lag.[13] Further, the Company

10 Dukes Rebuttal 7:3
11 Dukes Rebuttal 9:21
12 Dukes Rebuttal 9:1
13 UNS Response to RUCO 11.4

and Staff have discussed including information on the demands that various appliances and uses will place on the system and how they can impact a customer's bill.

Q. Will customers need to purchase demand control equipment or make expensive changes to avoid a higher bill under the new rate design?

A. No. Many customers, such as high load factor customers, will experience lower bills. For others, the focus of the Company's education program should be to assist customers to make usage and time-of-use decisions based on their own lifestyles. Simple actions such as not performing multiple electrical activities simultaneously (e.g., cooking, clothes drying and cooling) can be implemented by customers without any control equipment. Customers may decide to install a programmable thermostat (which should cost less than $75) for greater control.

Q. What protections has Staff sought to have in place before the transition takes place?

A. In part due to gradualism, Staff recommended that the demand charge established at the conclusion of the case be set at a partial cost level and apply only during the On-Peak time period to allow some load shifting. Also, Staff recommended that a mechanism be developed to determine if adverse effects are taking place and to keep the rate design portion of the case open to address any issues that may develop.

Besides these regulatory steps, Staff has requested a transition plan, which should be documented as a Plan of Action, well before the transition date. Staff expects that this Plan of Action will cover not only the items that the Company has suggested[14] but also milestones that may include meter data management testing, providing usage information to customers on pre-transition bills, the education and communications program, billing system stress

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[14] Exhibit DJD-R-1

testing, customer information systems stress testing, customer service training and on-going monitoring for adverse effects and regular reporting to Staff, Residential Utility Consumer Office ("RUCO") and other interested parties.

Q. The Company has proposed that all Residential and Small General Service customers would transition to Three-Part TOU rates in February or March 2017.[15] How does this compare to Staff's phased transition?

A. This is a more rapid transition than Staff proposed; however, a quicker transition is acceptable if the Company is able to successfully manage the transition as described above. The Company's proposal allows for two or three additional months of communications and education before customers begin a transition, which is positive since all customers are to be migrated at that time. Transitioning all customers during a single month of billing cycles can result in stressing various systems such as customer service. This is why Staff recommends that stress testing be included in the transition planning.

Q. What protections has Staff sought to include within the Three-Part TOU rate design?

A. In Staff's testimony of December 9th, Staff highlighted that there could be inadvertent effects from the transition. Subsequent to that testimony Staff continued the discussion, including the concept of a load factor floor, which the Company explored in detail and included in its rebuttal testimony.[16] The detailed analysis informally provided to Staff by the Company demonstrates that this concept prevents significant adverse effects and should be included in the Three-Part TOU rate design at implementation.

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[15] Dukes Rebuttal 11:7

[16] Dukes Rebuttal 7:22 and Jones Rebuttal 14:1

Q. Do you foresee any customer subgroups that should not be subject to mandatory transition?

A. Not beyond Staff witness Mr. Broderick's surrebuttal discussion concerning the provision of bill credits. Assuming all of the elements of the pre-transition Plan of Action are properly executed, specifically the education and information requirements, all customers will be given the knowledge to control their usage, time of usage and overlap of usage.

Q. How does Staff's recommended Three-Part TOU rate accommodate lifestyle and other situations?

A. Staff recognized (as did other parties[17]) that a "pure or perfect" Three-Part TOU rate would have multiple demand charges to perfectly price distribution, transmission and generation demand. Staff also recognized that implementation of the "pure or perfect" rate would have significant impacts (as did other parties) while customers learned to deal with the new rate and potentially change their electric controls. To avoid being trapped by the perfect, Staff recommended applying a single demand charge only to the existing On-Peak period. This decision eliminates the impact of holidays, weekend entertaining, the use of short-term high demand loads such as electric oven cleaning and hobbies.

Q. The Arizona Community Action Association ("ACAA") has argued that CARES and other low-income customers have limited opportunities to control their usage to avoid adverse impacts from a Three-Part TOU rate and should be exempt.

A. Staff's recommendation for a Three-Part TOU rate design recognizes that it provides an additional dimension (demand) for customers to make changes to lower their bills. Certain electrical usage such as food refrigeration is a 24 hour usage that is fairly level, but space and

[17] Overcast Rebuttal 33:14

water heating can be shifted if desired or controlled. More efficient lighting can be offered to rental tenants.

Staff recognizes that there is a learning curve and that is why they have worked with the Company to develop the load factor floor to protect against high demand readings. Staff insists that the Company's education program provide tools to help all customers identify and manage demand without devices and computers.

Staff's suggested Residential demand rate of $4.78[18] per kW applies only during On-Peak periods to minimize the impact on all customers and create windows that may work for them. The Company's updated proposed rate design recommends a demand rate of $5.15 per kW.[19]

ACAA has proposed a shadow billing service to show low-income customers how much they would have been billed under two-part rates and then credit them for the difference between the two- and three-part rate design.[20] The shadow billing concept proposed by ACAA results in maintaining the two-part rate for those months when a customer benefits and may require a customer to learn, and react to, two rates rather than one in order to minimize their bills. A clear transition with education, communications and protections as discussed will minimize complexity for low income and all other customers and is preferable. Therefore, Staff recommends that the "shadow bill" be rejected.

Q. Are Staff's recommendations interrelated?

A. Yes. As explained above, Staff's recommendation for a mandatory transition to a Three-Part TOU rate design is interrelated with a number of items:

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[18] $4.78 = 75 percent of ($5.65 and $ 0.73) UNSE Schedule G-6-1, lines 19 and 20 (Demand Distribution Primary and Secondary)

[19] Jones Rebuttal 13:5 and Exhibit CAJ-R-4, Schedule H-3 page 4

[20] Zwick Rebuttal 11:24

- Class revenue allocation that recognizes gradualism and the impacts of a new methodology and Gila River Unit #3
- Customer information and education
- An appropriate Basic Service Charge ("BSC")
- A demand charge that recognizes gradualism
- On-Peak demand only
- On-Peak periods as in effect now
- Significant protections against adverse effects
- Keeping the rate design portion of the case open

Q. Has the Company accepted Staff's interrelated items?

A. For the most part, the Company has accepted Staff's recommendations. The Company has not accepted Staff's revenue allocation as discussed above. The Company supports and has proposed further details relating to Staff's suggestions on information and education.[21] The Company has accepted Staff's proposed $15 BSC if the Commission adopts an acceptable three-part rate structure for all Residential and Small General Service customers.[22] While the Company has proposed a different basis for the On-Peak[23] demand charge, their $5.15/kW value is similar to Staff's $4.78/kW proposal. Working with Staff, the Company developed the 15 percent load factor floor to protect customers against adverse effects.[24] The Company also supports keeping the rate design portion of the case open to address issues that may develop.[25]

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[21] Dukes Rebuttal 9:14
[22] Dukes Rebuttal 7:10 and Hutchens Rebuttal 8:5
[23] Dukes Rebuttal 8:19
[24] Dukes Rebuttal 7:22 and Hutchens Rebuttal 8:25
[25] Dukes Rebuttal 10:18

Q. Why are these interrelationships important to Staff?

A. Subsequent to the submission on December 9th, Staff has worked with the Company to explore the detailed interrelationships to minimize the impact on customers. If any party seeks to reject Staff's Three-Part TOU rate design and the other interrelated items, then Staff may have to reconsider or shift some or all of its positions.

Q. Are there other interrelations in Staff's recommendation of a mandatory transition to Three-Part TOU rate design?

A. Yes. Staff considered other solutions to the problem caused by shifting fixed costs from vacant, seasonal and distributed generation ("DG") customers. While other solutions would require carving out subclasses and applying measurements to define inclusion or exclusion, Staff's long-term rate design proposal sets the foundation to deal with these concerns without arguing over whether one or more subclasses exist and which customers should be selected for different rates. As recommended by Staff, the Three-Part TOU rate does not cure every problem at the onset but provides the foundation for now and the future.

Q. Do the interrelationships apply to distributed generation?

A. Yes. The use of a Three-Part TOU rate will ensure that DG customers contribute to the recovery of the fixed costs of infrastructure that they continue to use even after their decision to connect to the Company's system, their use of the system as "storage" for their excess banked energy, their use of the system to provide frequency for their inverters and the use of the system to sell excess energy.

The addition of a demand charge and its resulting revenue stream reduces the required energy charge within any rate structure (for the same revenue requirement). If the Commission decides to retain net metering and/or banking of energy as Staff continues to recommend, the use of the Three-Part TOU rate has an impact on the compensation under net metering due to a reduced energy charge. Any decision to not implement Three-Part TOU rates must then reconsider whether net metering is overcompensating DG customers.

CARES

Q. Does Staff support the Company's proposal for CARES?

A. The Company is proposing to change the CARES program to be based upon the new Three-Part TOU rate and provide an 18 percent discount with a flat $16 discount applied for bills above 1,000 kWh.[26] CARES-Medical customers would receive a 24 percent discount with a flat $16 discount applied for bills above 2,000 kWh.[27]

The Company agrees with Staff that the total value of the CARES discount must be preserved.[28] Subject to a review of the impact as the final rates are finalized, Staff supports the Company's revised proposal.

BUY-THROUGH

Q. Several parties have proposed changes to the "Buy-Through" proposal submitted by the Company, does Staff support those changes?

A. Staff reiterates its position that the Buy-Through proposal should not impact any other customers. Care must be taken to ensure that if a customer is permitted to seek savings on its own and then later decides to return (for example when the power market tightens) all other customers must be protected from this return as well, which could have adverse effects on other regulated customers, and could be magnified if the volume cap of 10 MW is increased. Therefore, if the Buy-Through is approved on a permanent basis, then Staff recommends the

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[26] Jones Rebuttal 39:12
[27] Jones Rebuttal 39:15
[28] Jones Rebuttal 21:14

Company propose a market price for any customers that return. However, if the proposal is approved on a temporary basis until the next rate case, the Company may be amenable to addressing this issue in its next case.

LOST FIXED COST RECOVERY

Q. Why is only 50 percent of the non-generation related portion of the demand charge included in the LFCR?

A. The 50 percent mechanism, as approved by the Commission, recognizes that while some energy efficiency measures will reduce the energy consumption, they do not always reduce the demand component proportionally. For example, if a customer installs a setback thermostat for electrical space heating, during the setback period energy consumption will be reduced. Since thermostats are on-off devices, when the thermostat calls for heat at the end of the setback period the full load of the heating system will occur and therefore the demand measurement will not decrease in proportion to the energy decrease. That is why the 50 percent demand provision was proposed. It would be inappropriate to compensate for the entire demand amount when it is unlikely that all of the demand will disappear.

Q. The Company argues that fixed generation costs should be included in the LFCR.[29] Why are generation costs not included?

A. The Company's generation can be sold to all of its customers and neighboring utilities because it is connected through the transmission system as opposed to distribution facilities that cannot serve customers on a different feeder or substation.

The Company states that it must realize the approved level of billing determinants in future years to fully recover its fixed costs.[30] The Company also states that sales have decreased 8

[29] Jones Rebuttal 23:22
[30] Jones Rebuttal 24:12

percent between this test year and the last test year and categorizes "...this reduction is more than DG and EE related reductions..."[31].

For periods after the Test Year, the Company's Integrated Resource Plan shows a trend of increasing total numbers of customers[32] and the reference case shows increasing retail energy sales[33] and increasing peak demand.[34]

The LFCR is not designed to compensate for non-specific sales losses or business climate changes as it is not a full revenue decoupling mechanism, nor was the adoption of the LFCR accompanied by a reduction in the rate of return to reflect the shift of sales risk to customers. Adding generation to the LFCR due to the declining sales circumstances (in the recent past) noted by the Company would unacceptably shift risk to customers.

Q. The Company has expressed concern that "as long as solar production reduces overall retail volumes sold, the recovery of fixed costs is avoided."[35] Does this imply a difference in perspective between the Company and Staff?

A. Staff views anything that occurs behind the meter as the customer's private matter and an opportunity to control electricity usage. Therefore, a reduction in sales due to the addition of insulation, installation of higher efficiency HVAC equipment, and/or conservation due to customer lifestyle changes will affect the customer's energy consumption in a manner similar to a customer installing solar DG (absent the impact of excess production). Since the LFCR is reset after the end of a rate case, any lost sales due to installed solar DG or EE have already been accounted for in the Test Year billing determinants. From this perspective, Staff

[31] Jones rebuttal 24:22
[32] UNSE 2014 Integrated Resource Plan Chart 6 (page 39)
[33] UNSE 2014 Integrated Resource Plan Chart 8 (page 42)
[34] UNSE 2014 Integrated Resource Plan Chart 10 (page 44)
[35] Jones Rebuttal 28:17

envisions that the DG portion of the LFCR can be eliminated once Three-Part TOU rates are in place and charges fully reflect cost as anticipated upon conclusion of the next rate case.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

EXHIBIT
S-7
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

SUSAN BITTER SMITH
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
DOUG LITTLE
Commissioner
TOM FORESE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE FO RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

DIRECT

TESTIMONY

OF

BARBARA KEENE

PUBLIC UTILITIES ANALYST MANAGER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 6, 2015

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APPENDICES

EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-15-0142

This testimony will addresses power supply, Gila River Power Plant Unit 3 ("Gila River"), and base cost of fuel and purchased power for UNS Electric, Inc. ("UNSE" or "Company").

Staff's recommendations are as follows:

1. The $9.3 million of deferred non-fuel costs related to Gila River should be recovered through base rates over three years.
2. The deferred fuel and purchased power savings resulting from UNSE's acquisition of Gila River should be returned to customers through a PPFAC credit during the first year under new rates.
3. Because the deferred non-fuel costs related to Gila River include depreciation expense through April 2016, a timing adjustment of $2 million needs to be made to accumulated depreciation to reduce the amount of rate base associated with the Gila River plant because UNSE only included accumulated depreciation through December 2014.
4. Since the actual amounts of deferred costs and accumulated depreciation will not be known until April 2016, the numbers could be trued up at hearing or in post-hearing briefs in this case.
5. UNSE's acquisition of Gila River should be considered to be prudent.
6. The base cost of fuel and purchased power costs should be set at $0.053288 per kWh.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Barbara Keene. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Arizona Corporation Commission ("Commission") in the Utilities Division ("Staff") as a Public Utilities Analyst Manager. My duties include supervising the energy portion of the Telecommunications and Energy Section. A copy of my résumé is provided in Appendix 1.

Q. As part of your employment responsibilities, were you assigned to review matters contained in Docket No. E-04204A-15-0142?

A. Yes.

Q. What is subject matter of this testimony?

A. This testimony will address power supply, Gila River Power Plant Unit 3 ("Gila River"), and base cost of fuel and purchased power for UNS Electric, Inc. ("UNSE" or "Company").

POWER SUPPLY

Q. Please describe UNSE's power supply.

A. UNSE owns the following generation assets:

1. Black Mountain Generating Station, located in Kingman, Arizona, providing 90 MW of natural gas-fired combustion turbine capacity used primarily as peaking resources;

2. Valencia Power Plant, located in Nogales, Arizona, providing 63 MW of natural gas and diesel-fueled combustion turbine capacity used primarily as back-up supply for the city of Nogales and surrounding areas;

3. Solar photovoltaic facilities, consisting of the 7 MW Rio Rico facility in Santa Cruz County and the 1 MW La Senita facility in Mohave County; and

4. Gila River (UNSE's share is 137.5 MW), located in Gila Bend, Arizona, providing natural gas-fired combined cycle capacity used primarily to meet base load requirements in both Mohave and Santa Cruz counties.

GILA RIVER POWER PLANT UNIT 3

Q. Did UNSE acquire Gila River during the test year?

A. Yes. UNSE acquired a 25 percent interest in Gila River for about $55 million in December 2014. UNSE's affiliate, Tucson Electric Power ("TEP"), acquired 75 percent of the unit.

Q. Has the Commission issued a Decision related to UNSE and Gila River?

A. Yes. On January 22, 2015, the Commission issued Decision No. 74911 which authorized UNSE to defer for possible later recovery through rates (1) the non-fuel costs of owning, operating and maintaining its share of Gila River and (2) short-term fuel and purchased power savings associated with the purchase of Gila. No finding was made concerning the prudency of the purchase of Gila River for ratemaking purposes.

Q. Did Decision No. 74911 approve a Plan of Administration ("POA") to describe how the deferred accounting order would operate?

A. Yes.

Q. What are the major provisions of the POA?

A. The POA allows UNSE to defer certain defined non-fuel costs for the period of January 1, 2015, through the earlier of April 30, 2016, or the date new rates go into effect. It provides that the cumulative non-fuel costs will not exceed the lower of $10.5 million or the cumulative deferred savings as of April 30, 2016. For purposes of calculating the Purchased Power and Fuel Adjustment Clause ("PPFAC"), deferred savings will continue to accrue until new rates become effective; however, cumulative deferred costs will not increase after April 30, 2016.

Q. What are the allowable deferred costs?

A. The costs eligible for deferral are limited to:

1. Depreciation and amortization costs,
2. Property taxes,
3. Operating and maintenance expenses, and
4. Carrying costs (5 percent annual rate) on net book investment.

Q. What are the allowable deferred savings?

A. The savings eligible for deferral are limited to:

1. Energy costs based on published Palo Verde Hub day-ahead market prices from the Intercontinental Exchange for on-peak and off-peak power, less actual fuel costs, plus
2. Avoided long-term capacity procurement costs at $1.52 per kW/month, and offset by
3. Short-term wholesale sales revenue associated with Gila River.

Q. What has UNSE proposed in regard to applying the deferred savings and costs to rates?

A. UNSE has proposed that the deferred savings be returned to customers through a PPFAC credit during the first year under new rates and that the deferred costs be recovered from customers over a three-year period through base rates. UNSE has estimated that the deferred costs would total $9.3 million. Therefore, the Gila River Deferred Cost pro forma adjustment is $3.1 million ($9.3 million/3 years).

Q. Has Staff reviewed UNSE's calculations of the deferred savings and costs?

A. Yes. UNSE's calculations appear to be consistent with Decision No. 74911 and the POA.

Q. Does Staff agree that the deferred savings and costs should be applied to rates as proposed by UNSE?

A. Yes. The deferred savings and costs should be applied as proposed by UNSE if the Commission were to find that UNSE's acquisition of its share of Gila River was prudent. However, another pro forma adjustment needs to be made.

Q. What adjustment needs to be made?

A. Because the deferred costs include depreciation expense through April 2016, an adjustment needs to be made to accumulated depreciation to reduce the amount of rate base associated with the Gila River plant because UNSE only included accumulated depreciation through December 2014.

Q. Does Staff have a proposed amount for this timing adjustment?

A. Yes. UNSE has provided Staff with an estimate of $2 million for depreciation associated with Gila River from January 2015 through April 2016. Staff has compared that number to other available information and finds the $2 million estimate to be reasonable.

Q. Since the actual amounts of deferred costs and accumulated depreciation will not be known until April 2016, could there be a true-up at a later time in this case?

A. Yes, at hearing or in post-hearing briefs.

Q. Was there another Commission Decision involving UNSE and Gila River?

A. Yes. Among other items, Decision No. 74865 (December 18, 2014) authorized UNSE to issue new debt up to $35 million and accept new equity contributions from its parent up to $35 million, for the specific purpose of purchasing a share of Gila River, and to issue long-term debt to refinance the debt initially issued for the purchase of its share of Gila River. Decision No. 74865 did not constitute or imply approval of the purchase of the interest in Gila River.

Q. Has Staff considered whether UNSE's acquisition of Gila River was prudent?

A. Yes. Staff has considered several factors that are discussed below.

Q. Was UNSE's acquisition of its share of Gila River the result of a Request for Proposals ("RFP")?

A. Yes. TEP issued an RFP for a power plant purchase on May 10, 2013.

Q. Did TEP use an Independent Monitor to oversee the RFP process?

A. Yes. TEP selected Accion Group to serve as the Independent Monitor for this RFP.

Q. What did Accion Group report in regard to the RFP process?

A. Accion Group reported that the RFP was conducted fairly and without bias toward or against any offeror or type of generation acceptable under the terms of the RFP. TEP adhered to established protocols. Through a website, all registered users had access to the same information at the same time. Accion Group was satisfied that TEP had created an environment conducive to a fair and transparent process.

Q. What was the outcome of the RFP?

A. According to the direct testimony of UNSE witness Michael E. Sheehan (page 7), TEP received 14 different proposals from nine different bidders. Gila River was selected because of economic and operational advantages of the proposal.

Q. Why did UNSE decide to acquire part of Gila River?

A. Mr. Sheehan stated (page 7) that it made sense for UNSE to acquire a portion of Gila River through TEP's 2013 RFP process due to the unique opportunity to right-size the capacity to be acquired by UNSE as well as UNSE's need for base load generating capacity.

Q. Did UNSE consider entering into a long-term power purchase agreement as an alternative to purchasing Gila River Unit 3?

A. Yes. According to UNSE's response to STF 22.1, UNSE chose Gila River over a long-term power purchase agreement for several reasons. First, Gila River was seen as an opportunity to reduce UNSE's reliance on the wholesale power market, which provided over 97 percent of its energy needs prior to 2015. Second, a number of independent power producers were facing bankruptcy situations. The decision was made to acquire a long-term resource instead of entering into a potential risky long-term purchase power agreement to avoid counterparty risks and to acquire Gila River at a significant discount.

Q. What other reasons did UNSE provide for its acquisition of Gila River?

A. According to the direct testimony of UNSE witness David G. Hutchens (page 8), Gila River is one of the newest and most efficient power plants in Arizona. The acquisition of Gila River as UNSE's first base-load generating resource has helped to diversify UNSE's portfolio. In addition, the cost of $398 per kW to acquire Gila River was significantly lower that UNSE's estimated cost of $1,367 per kW to build a new unit.

Q. Has Staff reviewed UNSE's cost assumptions?

A. Yes. As part of its review of the financing application, Staff found estimates for the cost of a new combined cycle power plant around the size of Gila River to range from $950 per kW to $1,475 per kW in 2014 dollars. The $398 per kW paid for Gila River is considerably below those estimates.

Q. Are there operational benefits of Gila River?

A. Yes. Per Mr. Sheehan (p. 8), Gila River is situated so that it can receive natural gas transportation from both the El Paso Natural Gas and Transwestern Pipeline Company pipelines, providing access to both the Permian and San Juan supply basins. This offers operational advantages for both cost and reliability of the gas supply. In addition, Gila River's interconnection to the Palo Verde market hub and existing transmission rights to the Jojoba Switchyard provided lower transmission costs relative to other proposals.

Q. How has Gila River performed in 2015?

A. According to UNSE's response to STF 18.2, UNSE's share of Gila River generated 342.6 GWh as of August 2015. The capacity factor was 43.04 percent, the availability factor was 94.54 percent, and the equivalent forced outage rate was 11.91 percent. A scheduled outage occurred from March 10, 2015 through April 11, 2015.

Q. At this time, does Staff believe that UNSE's acquisition of Gila River was prudent?

A. Yes.

Q. Did UNSE include the cost of acquiring Gila River in the calculation of rate base?

A. Yes. The amount of $54,693,405, consisting of the net purchase price of $54,777,760 less December 2014 depreciation expense of $84,355, was included in rate base.

BASE COST OF FUEL AND PURCHASED POWER

Q. Please explain the adjustment for the base cost of fuel and purchased power ("base cost").

A. The adjustment reflects the difference between Staff's proposed base cost and UNSE's proposed base cost.

Q. What is UNSE's proposed base cost?

A. UNSE has proposed a base cost of $0.048427 per kWh. This results in a total expense of $77,522,386 based on test year retail sales of 1,600,809,167 kWh.

Q. How did UNSE determine its proposed base cost?

A. In his Direct Testimony (page 17), UNSE witness Michael Sheehan explains that UNSE used forward natural gas and wholesale price projections, as of April 2015, to forecast what fuel and purchased power cost would be from April 2016 through March 31, 2017. That timeframe reflects when new UNSE rates are likely to go into effect.

Q. Why did UNSE use forecasted fuel and purchased power costs instead of test year costs?

A. Per UNSE's response to STF 18.1, UNSE wanted to set the base cost as closely as possible to the cost expected to be incurred in the first year when rates established in the case would be in effect. In addition, test year costs do not reflect the inclusion of energy produced by Gila River and the corresponding reduced expenditures of purchasing power from the open market.

Q. Does Staff agree with UNSE's base cost?

A. No. Staff recommends a base cost of $0.053288 per kWh. This results in a total expense of $85,303,919 based on test year retail sales of 1,600,809,167 kWh

Q. Does Staff agree with UNSE's methodology for determining the base cost?

A. No. Staff does not believe that the base cost should be developed totally on forecasts. Staff agrees that test year costs without Gila River would not be reflective of costs going forward, but there are currently eight months in 2015 of actual data available with Gila River included.

Q. How did Staff determine its proposed base cost?

A. Staff used actual costs from January through August 2015, and UNSE's forecasted costs for September through December 2015.

Q. Is Staff addressing UNSE's proposed changes to the PPFAC?

A. Yes, but Staff will address UNSE's proposed changes to the PPFAC in rate design testimony.

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A. Staff's recommendations are as follows:

1. The $9.3 million of deferred non-fuel costs related to Gila River should be recovered through base rates over three years.

2. The deferred fuel and purchased power savings resulting from UNSE's acquisition of Gila River should be returned to customers through a PPFAC credit during the first year under new rates.

3. Because the deferred non-fuel costs related to Gila River include depreciation expense through April 2016, a timing adjustment of $2 million needs to be made to accumulated depreciation to reduce the amount of rate base associated with the Gila River plant because UNSE only included accumulated depreciation through December 2014.

4. Since the actual amounts of deferred costs and accumulated depreciation will not be known until April 2016, the numbers could be trued up at hearing or in post-hearing briefs in this case.

5. UNSE's acquisition of Gila River should be considered to be prudent.

6. The base cost of fuel and purchased power costs should be set at $0.053288 per kWh.

Q. Does this conclude your direct testimony?

A. Yes, it does.

RESUME

BARBARA KEENE

Education

B.S.	Political Science, Arizona State University (1976)
M.P.A.	Public Administration, Arizona State University (1982)
A.A.	Economics, Glendale Community College (1993)

Additional Training

Management Development Program - State of Arizona, 1986-1987
UPLAN Training - LCG Consulting, 1989, 1990, 1991
Various seminars, workshops, and conferences on ratemaking, energy efficiency, rate design, computer skills, labor market information, training trainers, and Census products

Employment History

Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Public Utilities Analyst Manager (May 2005-present). Supervise the energy portion of the Telecommunications and Energy Section. Conduct economic and policy analyses of public utilities. Coordinate working groups of stakeholders on various issues. Prepare Staff recommendations and present testimony on electric resource planning, rate design, special contracts, energy efficiency programs, and other matters.

Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Public Utilities Analyst V (October 2001-May 2005), Senior Economist (July 1990-October 2001), Economist II (December 1989-July 1990), Economist I (August 1989-December 1989). Conduct economic and policy analyses of public utilities. Coordinate working groups of stakeholders on various issues. Prepare Staff recommendations and present testimony on electric resource planning, rate design, special contracts, energy efficiency programs, and other matters. Responsible for maintaining and operating UPLAN, a computer model of electricity supply and production costs.

Arizona Department of Economic Security, Research Administration, Economic Analysis Unit: Labor Market Information Supervisor (September 1985-August 1989), Research and Statistical Analyst (September 1984-September 1985), Administrative Assistant (September 1983-September 1984). Supervised professional staff engaged in economic research and analysis. Responsible for occupational employment forecasts, wage surveys, economic development studies, and over 50 publications. Edited the monthly **Arizona Labor Market Information Newsletter**, which was distributed to about 4,000 companies and individuals.

Testimony

Resource Planning for Electric Utilities (Docket No. U-0000-90-088), Arizona Corporation Commission, 1990; testimony on production costs and system reliability.

Trico Electric Cooperative Rate Case (Docket No. U-1461-91-254), Arizona Corporation Commission, 1992; testimony on demand-side management and time-of-use and interruptible power rates.

Navopache Electric Cooperative Rate Case (Docket No. U-1787-91-280), Arizona Corporation Commission, 1992; testimony on demand-side management and economic development rates.

Arizona Electric Power Cooperative Rate Case (Docket No. U-1773-92-214), Arizona Corporation Commission, 1993; testimony on demand-side management, interruptible power, and rate design.

Tucson Electric Power Company Rate Case (Docket Nos. U-1933-93-006 and U-1933-93-066) Arizona Corporation Commission, 1993; testimony on demand-side management and a cogeneration agreement.

Resource Planning for Electric Utilities (Docket No. U-0000-93-052), Arizona Corporation Commission, 1993; testimony on production costs, system reliability, and demand-side management.

Duncan Valley Electric Cooperative Rate Case (Docket No. E-01703A-98-0431), Arizona Corporation Commission, 1999; testimony on demand-side management and renewable energy.

Tucson Electric Power Company vs. Cyprus Sierrita Corporation, Inc. (Docket No. E-0000I-99-0243), Arizona Corporation Commission, 1999; testimony on analysis of special contracts.

Arizona Public Service Company's Request for Variance (Docket No. E-01345A-01-0822), Arizona Corporation Commission, 2002; testimony on competitive bidding.

Generic Proceeding Concerning Electric Restructuring Issues (Docket No. E-00000A-02-0051), Arizona Corporation Commission, 2002; testimony on affiliate relationships and codes of conduct.

Tucson Electric Power Company's Application for Approval of New Partial Requirements Service Tariffs, Modification of Existing Partial Requirements Service Tariff 101, and Elimination of Qualifying Facility Tariffs (Docket No. E-01933A-02-0345) and Application for Approval of its Stranded Cost Recovery (Docket No. E-01933A-98-0471), Arizona Corporation Commission, 2002, testimony on proposals to eliminate, modify, or introduce tariffs and testimony on the modification of the Market Generation Credit.

Arizona Public Service Company's Application for Approval of Adjustment Mechanisms (Docket No. E-01345A-02-0403), Arizona Corporation Commission, 2003, testimony on the proposed Power Supply Adjustment and the proposed Competition Rules Compliance Charge.

Generic Proceeding Concerning Electric Restructuring Issues, et al (Docket No. E-00000A-02-0051, et al), Arizona Corporation Commission, 2003-2005; Staff Report and testimony on Code of Conduct.

Arizona Public Service Company Rate Case (Docket No. E-01345A-03-0437), Arizona Corporation Commission, 2004; testimony on demand-side management, system benefits, renewable energy, the Returning Customer Direct Assignment Charge, and service schedules.

Arizona Electric Power Cooperative Rate Case (Docket No. E-01773A-04-0528), Arizona Corporation Commission, 2005; testimony on a fuel and purchased power cost adjustor, demand-side management, and rate design.

Trico Electric Cooperative Rate Case (Docket No. E-01461A-04-0607), Arizona Corporation Commission, 2005; testimony on the Environmental Portfolio Standard; demand-side management; special charges; and Rules, Regulations, and Line Extension Policies.

Arizona Public Service Company (Docket Nos. E-01345A-03-0437 and E-01345A-05-0526), Arizona Corporation Commission, 2005; testimony on the Plan of Administration of the Power Supply Adjustor.

Arizona Public Service Company Emergency Rate Case (Docket No. E-01345A-06-0009), Arizona Corporation Commission, 2006; testimony on bill impacts.

Arizona Public Service Company Rate Case (Docket Nos. E-01345A-05-0816, E-01345A-05-0826, and E-01345A-05-0827), Arizona Corporation Commission, 2006; testimony on funding for renewable resources, net metering, green pricing tariffs, and a Power Supply Adjustor surcharge.

Tucson Electric Power Company Filing to Amend Decision No. 62103 (Docket No. E-01933A-05-0650), Arizona Corporation Commission, 2007, testimony on demand-side management, time-of-use, direct load control, and renewable energy.

Consideration, Pursuant to A.R.S. § 40-252 to Modify Decision No. 67744 Relating to the Self-Build Option (Docket No. E-01345A-07-0420), Arizona Corporation Commission, 2008, testimony on the self-build option for Arizona Public Service Company.

Sempra Energy Solutions Application for Certificate of Convenience and Necessity (Docket No. E-03964A-06-0168), Arizona Corporation Commission, 2008, testimony on the overall fitness of Sempra Energy Solutions to provide competitive retail electric service in Arizona.

Tucson Electric Power Company Rate Case (Docket No. E-01933A-07-0402), Arizona Corporation Commission, 2008, testimony in support of the Settlement Agreement regarding renewable energy, demand-side management, Rules and Regulations, partial requirements service tariffs, interruptible tariff, demand response, and bill estimation.

Arizona Public Service Company Rate Case (Docket No. E-01345A-08-0172), Arizona Corporation Commission, 2009, testimony in support of the Settlement Agreement regarding Power Supply

Adjustment Plan of Administration, treatment of Schedule 3, withdrawal of APS' Impact Fee proposal, withdrawal of APS' System Facilities Charge proposal, revisions to Schedule 3, demand-side management, and renewable energy.

Trico Electric Cooperative Application for Approval of a Net Metering Tariff (Docket No. E-01461A-09-0450), Arizona Corporation Commission, 2010, testimony on net metering administrative charge.

Southwest Gas Corporation rate case (Docket No. G-01551A-10-0458), Arizona Corporation Commission, 2011, testimony in support of the Settlement Agreement regarding energy efficiency and renewable energy resource technology.

Publications

Author of the following articles published in the *Arizona Labor Market Information Newsletter*:

"1982 Mining Employees - Where are They Now?" - September 1984
"The Cost of Hiring" and "Arizona's Growing Industries" - January 1985
"Union Membership - Declining or Shifting?" - December 1985
"Growing Industries in Arizona" - April 1986
"Women's Work?" - July 1986
"1987 SIC Revision" - December 1986
"Growing and Declining Industries" - June 1987
"1986 DOT Supplement" and "Consumer Expenditure Survey" - July 1987
"The Consumer Price Index: Changing With the Times" - August 1987
"Average Annual Pay" - November 1987
"Annual Pay in Metropolitan Areas" - January 1988
"The Growing Temporary Help Industry" - February 1988
"Update on the Consumer Expenditure Survey" - April 1988
"Employee Leasing" - August 1988
"Metropolitan Counties Benefit from State's Growing Industries" - November 1988
"Arizona Network Gives Small Firms Helping Hand" - June 1989

Major contributor to the following books published by the Arizona Department of Economic Security:

Annual Planning Information - editions from 1984 to 1989
Hispanics in Transition - 1987

(with David Berry) "Contracting for Power," *Business Economics*, October 1995.

(with Robert Gray) "Customer Selection Issues," *NRRI Quarterly Bulletin*, Spring 1998.

Reports

(with Task Force) *Report of the Task Force on the Feasibility of Implementing Sliding Scale Hookup Fees.* Arizona Corporation Commission, 1992.

Customer Repayment of Utility DSM Costs, Arizona Corporation Commission, 1995.

(with Working Group) *Report of the Participants in Workshops on Customer Selection Issues*," Arizona Corporation Commission, 1997.

"DSM Workshop Progress Report," Arizona Corporation Commission, 2004.

(with Erin Casper) "Staff Report on Demand Side Management Policy," Arizona Corporation Commission, 2005.

"Staff Report on Interconnection for the Generic Investigation of Distributed Generation," Arizona Corporation Commission, 2007.

EXHIBIT
S-8
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

SUSAN BITTER SMITH
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
DOUG LITTLE
Commissioner
TOM FORESE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. 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 UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

DIRECT RATE DESIGN

TESTIMONY

OF

BARBARA KEENE

PUBLIC UTILITIES ANALYST MANAGER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

DECEMBER 9, 2015

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EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-15-0142

This testimony addresses UNSE's proposed modifications to its Purchased Power and Fuel Adjustment Clause ("PPFAC").

Staff's recommendations are as follows:

1. The PPFAC rate should remain as a dollar per kWh rate.

2. The rate band should remain at 0.83 percent.

3. The proposed Base Rate Annual Adjustment should not be approved.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Barbara Keene. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Have you previously filed testimony in this docket?

A. Yes. I filed direct testimony concerning power supply, Gila River Power Plant Unit 3, and base cost of fuel and purchased power for UNS Electric, Inc. ("UNSE" or "Company").

Q. What is subject matter of this rate design testimony?

A. This testimony will address UNSE's proposed modifications to its Purchased Power and Fuel Adjustment Clause ("PPFAC").

PROPOSED MODIFICATIONS TO PPFAC

Q. What is the purpose of a PPFAC?

A. The purpose of a PPFAC is to track changes in the costs of obtaining power supplies. The costs of obtaining power supplies included in the base rates approved by the Commission in a rate case are compared to actual power supply costs incurred after the rate case. A PPFAC rate is used to bill or refund to customers the difference in costs.

Q. How does UNSE's PPFAC work?

A. The PPFAC Plan of Administration ("POA") describes how the PPFAC works. UNSE's PPFAC uses a historical 12-month rolling average of actual fuel, purchased power, and purchased transmission costs to reset the PPFAC rate each month without Commission approval. The actual costs are compared to the Average Base Cost of Fuel and Purchased Power approved in UNSE's last rate case.

Decision No. 74235 approved $0.05706 per kilowatt-hour ("kWh") as the Average Base Cost of Fuel and Purchased Power. As of December 1, 2015, the PPFAC rate was negative $0.000978 per kWh.

The change in the PPFAC rate is banded so that the new monthly PPFAC rate cannot increase or decrease the preceding month's Total Average Retail Fuel and Purchased Power Rate (the average base cost of fuel and purchased power plus the preceding month's PPFAC rate) by more than 0.83 percent.

Any over- or under-recovery of actual costs is recorded in the PPFAC bank balance, with interest. If the bank balance becomes over-collected by more than $10 million, UNSE must file for a PPFAC rate adjustment within 45 days or contact Staff to discuss why a rate adjustment is not necessary at that time. If the bank balance is under-collected, UNSE has the right to file an application with the Commission requesting a surcharge.

Q. What modifications has UNSE proposed for its PPFAC?

A. UNSE witness Craig A. Jones (Direct Testimony, pages 72-73, and Exhibit CAJ-5) has proposed the following modifications to the PPFAC:

1. The monthly PPFAC rate would be set as a percentage to be applied to the base cost of fuel and purchased power embedded in base rates for each rate class instead of as a dollar per kWh rate billed to all customers;
2. The rate band would be increased from 0.83 percent per month to 1 percent per month; and
3. A Base Rate Annual Adjustment would be added.

Q. Please describe UNSE's proposal to apply the PPFAC rate as a percentage.

A. As proposed by UNSE in this rate case, each customer class rate schedule has an unbundled rate component titled Base Power. Time-of-use rate schedules have separate Base Power rates for on-peak and off-peak times. Rate schedules with seasonal rates have additional Base Power rates. UNSE is proposing that the PPFAC rate be set as a percentage to be applied to the Base Power component(s) of each rate schedule. Currently, the PPFAC rate is simply a dollar per kWh rate that is multiplied by the monthly kWh used by each customer.

Q. Does Staff agree with UNSE's proposed percentage PPFAC rate?

A. No. It adds a great amount of complexity that is not needed, and it may shift costs among customer classes.

Q. Please describe UNSE's proposal to increase the rate band from 0.83 percent per month to 1 percent per month.

A. As described above, the band prevents the PPFAC rate from having very large increases or decreases. Mr. Jones (Direct Testimony, page72) states that the rate band should be increased because of the reduction in fuel and purchased power expenses caused by the purchase of Gila River and because of low commodity prices implied in forward markets.

Q. Does Staff agree with UNSE's proposed increase in the rate band?

A. No. A reduction in costs does not justify an increase in the rate band. The monthly 0.83 percent rate band prevents customers from experiencing more than a 10 percent increase over a year without Commission approval.

Q. What is Staff's recommendation regarding the rate band?

A. Staff recommends that the rate band remain at 0.83 percent.

Q. Please describe UNSE's proposed Base Rate Annual Adjustment.

A. Mr. Jones (Direct Testimony, page 73) states that the Base Rate Annual Adjustment is intended to improve the correlation between actual base rate collections and the approved base rate. He states that the variances between actual and approved base rate collections are driven by changing customer behavior.

Q. What is Staff's recommendation regarding the proposed Base Rate Annual Adjustment?

A. Staff recommends that the Base Rate Annual Adjustment not be approved, because the purpose of the PPFAC is to track fuel and purchased power costs, not to adjust for variations in base rate revenues due to changing customer behavior.

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A. Staff's recommendations are as follows:

1. The PPFAC rate should remain as a dollar per kWh rate.
2. The rate band should remain at 0.83 percent.
3. The proposed Base Rate Annual Adjustment should not be approved.

Q. Does this conclude your direct rate design testimony?

A. Yes, it does.

EXHIBIT

S-9

ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
Commissioner
ANDY TOBIN
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE FO RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

SURREBUTTAL

TESTIMONY

OF

BARBARA KEENE

PUBLIC UTILITIES ANALYST MANAGER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2016

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EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-15-0142

This surrebuttal testimony addresses the deferred costs and savings associated with Gila River Power Plant Unit 3. This testimony also responds to UNS Electric rebuttal witness Michael E. Sheehan in regard to the base cost and proposed modifications to the Purchased Power and Fuel Adjustment Clause ("PPFAC").

Staff's recommendations are as follows:

1. UNSE should update the base cost, based on most recent actual costs, prior to establishing new rates in this case.
2. Instead of approving the proposed Base Rate Annual Adjustment, the formula used for calculating the monthly PPFAC rate should be modified to include consideration of the bank balance.
3. At the time of implementation of new rates, the deferred non-fuel costs associated with Gila River should be netted against the deferred fuel and purchased power savings, with any remaining savings to flow through the PPFAC. The $3.1 million amortized deferred cost should be removed from the proposed revenue requirement.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Barbara Keene. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Have you previously filed testimony in this docket?

A. Yes. I filed direct testimony concerning power supply, Gila River Power Plant Unit 3 ("Gila River"), and base cost of fuel and purchased power ("base cost") for UNS Electric, Inc. ("UNSE" or "Company") and direct rate design testimony concerning UNSE's proposed modifications to its Purchased Power and Fuel Adjustment Clause ("PPFAC").

Q. What is the subject matter of this surrebuttal testimony?

A. This surrebuttal testimony will further address the deferred costs and savings associated with Gila River. This testimony will also respond to UNSE rebuttal witness Michael E. Sheehan in regard to the base cost and proposed modifications to the PPFAC.

DEFERRED COSTS AND SAVINGS ASSOCIATED WITH GILA RIVER

Q. Did you address deferred costs and savings associated with Gila River in your direct testimony in this case?

A. Yes.

Q. Please summarize Commission Decision No. 74911.

A. Decision No. 74911, (January 22, 2015) authorized UNSE to defer for possible later recovery through rates (1) the non-fuel costs of owning, operating, and maintaining its share of Gila River and (2) the short-term fuel and purchased power savings associated with the purchase of Gila River. Decision No. 74911 approved a Plan of Administration ("POA") that describes how the deferred accounting order would operate.

Q. Please describe the major provisions of the POA.

A. The POA allows UNSE to defer certain defined non-fuel costs[1] for the period of January 1, 2015, through the earlier of April 30, 2016, or the date new rates go into effect. It provides that the cumulative non-fuel costs will not exceed the lower of $10.5 million or the cumulative deferred savings as of April 30, 2016. For purposes of calculating the PPFAC, deferred savings will continue to accrue until new rates become effective; however, cumulative deferred costs will not increase after April 30, 2016.

Q. Has anything recently happened in regard to the POA since the filing of Staff's direct testimony?

A. Yes. On December 18, 2015, UNSE filed a motion in Docket No. E-04204A-13-0476 to amend the POA approved in Decision No. 74911. The motion asks to (1) extend the deferral period for the non-fuel costs from April 30, 2016, until the date that new rates go into effect in the pending rate case and (2) remove the $10.5 million hard cap on deferred costs and allow a deferred cost up to the amount of deferred savings.

Q. What does Staff now recommend in this rate case regarding the deferred costs and savings associated with Gila River?

A. Staff recommends that the deferred costs be netted against the deferred savings at the time of implementation of new rates, with any remaining savings to flow through the PPFAC. Therefore, Staff is removing the $3.1 million amortized deferred cost from the proposed

[1] Allowable deferred costs are limited to depreciation and amortization costs, property taxes, operating and maintenance expenses, and carrying costs (5 percent annual rate) on net book investment.

revenue requirement, as discussed in the surrebuttal testimony of Staff witness Donna Mullinax.

BASE COST OF FUEL AND PURCHASED POWER

Q. What did Staff recommend in direct testimony as the base cost of fuel and purchased power ("base cost") for UNSE?

A. In direct testimony, Staff recommended that the base cost be set at $0.053288 per kWh.

Q. What methodology did Staff use to determine its proposed base cost?

A. Staff used the available actual costs from January through August 2015, and UNSE's forecasted costs for September through December 2015. UNSE had originally proposed a base cost using only forecasted costs.

Q. What did Mr. Sheehan propose in his rebuttal testimony regarding the base cost?

A. Mr. Sheehan has recalculated the base cost as $0.053689 per kWh, using actual costs from January through December of 2015. UNSE proposes to again update the base cost based on actual costs prior to establishing new rates in this case.

Q. Does Staff accept Mr. Sheehan's rebuttal proposals in regard to the base cost?

A. Yes.

Q. In its rebuttal testimony, did UNSE allocate the base cost to the various rate classes?

A. Yes. UNSE rebuttal witness Craig A. Jones included tables in his testimony that indicate the base cost has been allocated among the rate classes.

Q. Is Staff in agreement with the class allocation of the base cost?

A. No. UNSE has not provided its methodology used for the allocation.

Q. What is Staff's recommendation?

A. Until such time as UNSE provides its class allocation methodology for review, Staff recommends that the base cost be used as the same dollar per kWh for all rate classes.

PROPOSED MODIFICATIONS TO PPFAC

Q. What is the purpose of a PPFAC?

A. The purpose of a PPFAC is to track changes in the costs of obtaining power supplies. The costs of obtaining power supplies included in the base rates approved by the Commission in a rate case are compared to actual power supply costs incurred after the rate case. A PPFAC rate is used to bill or refund to customers the difference in costs.

Q. How does UNSE's PPFAC work?

A. The PPFAC POA describes how the PPFAC works. UNSE's PPFAC uses a historical 12-month rolling average of actual fuel, purchased power, and purchased transmission costs to reset the PPFAC rate each month without Commission approval. The actual costs are compared to the Average Base Cost of Fuel and Purchased Power approved in UNSE's last rate case.

The change in the PPFAC rate is banded so that the new monthly PPFAC rate cannot increase or decrease the preceding month's Total Average Retail Fuel and Purchased Power Rate (the average base cost of fuel and purchased power plus the preceding month's PPFAC rate) by more than 0.83 percent.

Any over- or under-recovery of actual costs is recorded in the PPFAC bank balance, with interest. If the bank balance becomes over-collected by more than $10 million, UNSE must file for a PPFAC rate adjustment within 45 days or contact Staff to discuss why a rate adjustment is not necessary at that time. If the bank balance is under-collected, UNSE may file an application with the Commission requesting a surcharge.

The monthly calculation of the PPFAC rate does not consider the bank balance. The only way for over- or under-recovery of funds to be addressed is for UNSE to file for Commission approval of a PPFAC rate adjustment.

Q. Does Mr. Sheehan's rebuttal testimony continue to request a Base Rate Annual Adjustment?

A. Yes.

Q. What is the purpose of the Base Rate Annual Adjustment?

A. Mr. Sheehan states that the purpose of the Base Rate Annual Adjustment is to reduce the difference between the actual and approved collections of the base power supply costs related to changes in customer usage patterns relative to the base year.

Q. Does Staff still oppose the proposed Base Rate Annual Adjustment?

A. Yes. However, Staff proposes an alternative.

Q. What is Staff's alternative?

A. Staff recommends that the formula used for calculating the monthly PPFAC rate be modified to include consideration of the bank balance. This would be much simpler than the very complicated formula of the proposed Base Rate Annual Adjustment and it would maintain the purpose of the PPFAC.

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A. Staff's recommendations are as follows:

1. UNSE should again update the base cost, based on actual costs, prior to establishing new rates in this case.
2. Instead of approving the proposed Base Rate Annual Adjustment, the formula used for calculating the monthly PPFAC rate should be modified to include consideration of the bank balance.
3. At the time of implementation of new rates, the deferred non-fuel costs associated with Gila River should be netted against the deferred fuel and purchased power savings, with any remaining savings to flow through the PPFAC. The $3.1 million amortized deferred cost should be removed from the proposed revenue requirement.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

SUSAN BITTER SMITH
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
DOUG LITTLE
Commissioner
TOM FORESE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. 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 UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

DIRECT

TESTIMONY

OF

ERIC VAN EPPS

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 6, 2015

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EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-15-0142

This testimony addresses the proposed pro forma adjustments to operating income from the Transmission Cost Adjustor ("TCA"), Demand-side Management ("DSM"), and Renewable Energy Standard and Tariff ("REST") adjustors.

UNS Electric, Inc. ("UNSE") has proposed Revenue Requirement Adjustments which reduce Operating Income by $14.531 million for the TCA and $1.534 million for the REST & DSM adjustors. Staff has reviewed these adjustments and made recommendations in the testimony to follow.

INTRODUCTION

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

A. My name is Eric Van Epps. I am a Public Utilities Analyst employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst.

A. In my capacity as a Public Utilities Analyst, I provide recommendations to the Commission on matters involving electric and gas utilities. I also perform studies on ancillary issues pertaining to matters in and around the electric utility industry. I have been employed with the Commission for three years.

Q. What is the scope of your testimony in this case?

A. I will address the Transmission Cost Adjustor ("TCA"), Demand-side Management ("DSM") and Renewable Energy Standard and Tariff ("REST") for UNS Electric, Inc. ("UNSE" or "Company").

Q. Have you reviewed the testimony submitted by the Company in this case?

A. Yes. I reviewed the testimonies of Company witnesses, Mr. Craig A. Jones and Mr. David J. Lewis, specifically the Open Access Transmission Tariff ("OATT"), REST and DSM revenue requirement adjustments.

Mr. Jones is proposing a revenue requirement adjustment which reduces operating income by $14.531 million. This adjustment is associated with moving the 2015 OATT rate into base rates. Mr. Lewis is proposing a revenue requirement adjustment which reduces operating income by $1.534 million. This adjustment excludes, from test-year revenue, expense activity directly related to REST and DSM adjustor programs.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Please summarize your Revenue Requirement adjustment recommendations.

A. My revenue requirement adjustment recommendations are summarized in the following table:

Table 1

		Per Company	Per Staff	Staff Adjustment
OATT		$14,531,456	$14,511,531	($19,925)
REST & DSM		$1,534,105	$1,534,105	--

TRANSMISSION COST ADJUSTOR ("TCA")

Q. Why has the Company requested a revenue requirement adjustment for the TCA?

A. The methodology approved in UNSE's last rate case provided for a transmission cost recovery mechanism that is collected partly in base rates through the OATT with the remaining costs collected through the TCA rates. UNSE is required to update its transmission rate annually with new rates going into effect the first billing cycle in June. The proposed OATT revenue adjustment is a product of the Company's 2015 TCA filing.

Q. What is the OATT?

A. The OATT is a rate schedule approved by the Federal Energy Regulatory Commission ("FERC"). A portion of the transmission costs UNSE is authorized to recover is embedded in UNSE's base rates (established in the last rate case). FERC has approved a "formula rate" for UNSE through which the OATT rates are revised each year. When a new OATT rate is calculated each year, the difference between the new OATT rate and the portion already embedded in base rates is collected through the TCA.

Each year, Staff reviews the data supporting the new OATT calculations and the support for the revised TCA rates. Staff and UNSE work to resolve any discrepancies Staff may uncover in the calculation.

Q. Do you accept the Company's OATT pro forma adjustment to reduce operating income by $14,531,456?

A. Not entirely. On May 1, 2015, UNSE filed with the Commission its proposed TCA rates. Subsequent to the filing, UNSE and Staff discussed revisions to the proposed TCA rates. As a result of such discussions, UNSE ultimately filed revised TCA rates on May 28, 2015. The revised TCA rate filing adopted an updated OATT revenue requirement of $14,511,531. Therefore, Staff recommends revising the revenue adjustment to incorporate the updated OATT revenue requirement filed on May 28, 2015.

Q. Why did Staff have UNSE revise its proposed TCA filing?

A. Staff requested that UNSE update its TCA filing to reflect credits for revenues collected from short-term transmission services. In addition, Staff found other clerical discrepancies which, when corrected, caused a change in the proposed rates.

DEMAND-SIDE MANAGEMENT ("DSM")

Q. Why has the Company requested a revenue requirement adjustment for its DSM program?

A. The DSM program has a separate funding mechanism. Thus, UNSE has requested that the expense activity directly related to the DSM program be excluded from test-year revenue and expenses.

Q. What is the expense activity directly related to the DSM program?

A. Based on the Company's working papers, the DSM program incurred $40,330 in expenses during the 2014 test year.

Q. Were you able to reconcile DSM expenses against the Company's Annual DSM Progress Report?

A. Yes, within a de minimis amount Staff was able to reconcile the working papers against the Annual DSM Progress Report.

RENEWABLE ENERGY STANDARD AND TARIFF ("REST")

Q. Why has the Company requested a revenue requirement adjustment for its REST program?

A. The REST program has a separate funding mechanism. Thus, UNSE has requested that the expense activity directly related to the REST program be excluded from test-year revenue and expenses.

Q. What is the expense activity directly related to the REST program?

A. Based on the Company's working papers, the REST program incurred $1,493,776 in expenses during the 2014 test year.

Q. Were you able to reconcile REST expenses against the Company's Annual REST Compliance Report?

A. Yes, within a de minimis amount Staff was able to reconcile the working papers against the Annual REST Compliance Report.

Q. Do you accept the Company's REST and DSM pro forma adjustments to reduce operating income by a total of $1,534,105.76?

A. Yes, the pro forma adjustment which reduces operating income by $1,534,106 is reasonable and adequately excludes revenue and expense activity directly related to monies collected through the REST and DSM adjustor programs.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT

S-11

ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

SUSAN BITTER SMITH
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
DOUG LITTLE
Commissioner
TOM FORESE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. 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 UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

DIRECT

RATE DESIGN

TESTIMONY

OF

ERIC VAN EPPS

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

DECEMBER 9, 2015

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EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-15-0142

This testimony addresses proposed Rate Design recommendations for the Transmission Cost Adjustor ("TCA"), Demand-side Management ("DSM"), and Renewable Energy Standard and Tariff ("REST") adjustment mechanisms.

UNS Electric, Inc. ("UNSE") has not proposed any significant changes to the aforementioned adjustors other than an adjustment to how the CARES Program affects the DSM adjustor.

Staff recommends that UNSE update its TCA Plan of Administration ("POA") and file POA's for the existing DSM and REST adjustors.

INTRODUCTION

Please state your name, occupation, and business address.

A. My name is Eric Van Epps. I am a Public Utilities Analyst employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst.

A. In my capacity as a Public Utilities Analyst, I provide recommendations to the Commission on matters involving electric and gas utilities. I also perform studies on ancillary issues pertaining to matters in and around the electric utility industry. I have been employed with the Commission for three years.

Q. Have you previously filed testimony in this docket?

A. Yes, I filed direct testimony concerning the pro-forma adjustments to the Transmission Cost Adjustor ("TCA"), Demand-side Management ("DSM") and Renewable Energy Standard and Tariff ("REST") for UNS Electric, Inc. ("UNSE" or "Company"). This rate design testimony addresses other aspects of the adjustors.

Q. Have you reviewed the testimony submitted by the Company in this case?

A. Yes. I reviewed the testimony of Company witness, Mr. Craig A. Jones. Mr. Jones has not proposed any changes to the TCA or REST adjustor. Mr. Jones has proposed a change to the DSM Surcharge Rate Schedule (Rider R-2) to reflect his proposed change to the CARES program which would affect the DSM adjustor. The proposed change to the CARES program would no longer exempt CARES customers from paying the DSM Surcharge.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Please summarize your direct rate design recommendations.

A. My direct rate design recommendations are as follows, Staff recommends that UNSE file Plan(s) of Administration ("POA") for both the DSM and REST adjustors. Further, Staff recommends that UNSE look at the POA of Tucson Electric Power Company ("TEP") and provide draft POAs for both the aforementioned adjustors in rebuttal testimony. Further, Staff recommends that UNSE update its TCA POA, consistent with the discussions it had with Staff and provide a draft in its rebuttal testimony.

TRANSMISSION COST ADJUSTOR

Q. Are there changes the Company wishes to make to the TCA POA?

A. Yes, the Company has indicated in a data response that it wishes to make changes to its existing TCA POA that reflect recommendations from Staff after the filing date of its rate case.

Q. Has the Company provided Staff with its proposed changes to the TCA?

A. No, other than the initial conversation with Staff regarding changes to the TCA, while processing the Company's Annual TCA filing, Staff has not been provided the Company's proposed changes.

Q. How does Staff recommend the Company proceed?

A. Staff recommends that the Company clearly outline why it wishes to change its existing TCA, and provide a draft TCA POA in rebuttal testimony for Staff's review.

DEMAND-SIDE MANAGEMENT

Q. Has the Company requested any changes to its current DSM adjustor?

A. Yes, the Company has requested a change to the DSM Surcharge Rate Schedule (Rider R-2) to reflect a proposed change to the CARES program which would affect the DSM adjustor. The proposed change to the CARES program would no longer exempt CARES customers from paying the DSM Surcharge.

Q. Has the CARES Program been addressed in other congruent testimony?

A. Yes, Howard Solganick has addressed the Company's proposed changes to the CARES Program in his rate design testimony.

Q. Are there any other issues with the DSM adjustor that staff wishes to address?

A. Yes, currently UNSE does not have a POA on file for its DSM adjustor.

Q. Why is the absence of a DSM POA a concern for Commission Staff?

A. The DSM adjustor is a complex adjustor mechanism with functions that should be outlined in a POA so that current and future staff at both the Company and Commission can be in agreement as to how the Adjustor is intended to operate.

Q. Should the Company create a POA for its DSM Adjustor?

A. Yes, Staff recommends that the Company provide in its rebuttal testimony a draft DSM POA for Staff review. Further Staff requests UNSE address the scope and type of costs eligible for recovery in its draft POA.

RENEWABLE ENERGY STANDARD AND TARIFF

Q. Has the Company requested any changes to its current REST adjustor?

A. No, adjustments to the REST adjustor are typically addressed in the Company's Annual REST Filing.

Q. Are there any other issues with the REST adjustor that staff wishes to address?

A. Yes, currently UNSE does not have a POA on file for its REST adjustor.

Q. Why is the absence of a REST POA a concern for Commission Staff?

A. The REST adjustor is a complex adjustor mechanism with functions that should be outlined in a POA so that current and future staff at both the Company and Commission can be in agreement as to how the Adjustor is intended to operate.

Q. Should the Company create a POA for its REST Adjustor?

A. Yes, Staff recommends that the Company provide in its rebuttal testimony a draft REST POA for Staff review. Further Staff requests UNSE address the scope and type of costs eligible for recovery in its draft POA.

Q. Does this conclude your direct rate design testimony?

A. Yes, it does.

EXHIBIT
S-12
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
Commissioner
ANDY TOBIN
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. 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 UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

SURREBUTTAL

TESTIMONY

OF

ERIC VAN EPPS

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2016

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EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-15-0142

This Surrebuttal testimony responds to UNS Electric, Inc. ("UNSE" or "Company") witnesses Jones, Smith and Tilghman as well as to Southwest Energy Efficiency Project ("SWEEP"). These responses focus on the Transmission Cost Adjustor ("TCA"), Demand-side Management ("DSM"), and Renewable Energy Standard and Tariff adjustment mechanisms.

UNSE is in agreement with Staff's recommendations to create a Plan of Administration ("POA") for each of the aforementioned adjustors.

Staff opposes SWEEP's request for proposing and approving new DSM programs in this rate case as well as the inclusion of DSM funds through base rates. Staff recommends that there be considerations made for new DSM programs in future implementation plans and that the Company include in their education program for three-part rates information on how Energy Efficiency can mitigate the impacts of demand charges.

INTRODUCTION

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

A. My name is Eric Van Epps. I am a Public Utilities Analyst employed by the Arizona Corporation Commission ("Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst.

A. In my capacity as a Public Utilities Analyst, I provide recommendations to the Commission on matters involving electric and gas utilities. I also perform studies on ancillary issues pertaining to matters in and around the electric utility industry. I have been employed with the Commission for three years.

Q. Have you previously filed testimony in this docket?

A. Yes, I previously provided Direct and Direct Rate Design testimony relating to the Transmission Cost Adjustor ("TCA"), Demand-side Management ("DSM") and Renewable Energy Standard and Tariff ("REST") for UNS Electric, Inc. ("UNSE" or "Company").

Q. What is the purpose of your Surrebuttal testimony?

A. My Surrebuttal testimony provides Staff's responses to rebuttal testimony filed by the Company along with direct testimony filed by some of the interveners.

DIRECT RATE DESIGN TESTIMONY RECOMMENDATIONS

Q. Please summarize your Direct Rate Design testimony recommendations.

A. In Direct Rate Design testimony, Staff recommended that UNSE file a Plan of Administration ("POA") for both the DSM and REST adjustors. Further, Staff recommended that UNSE provide draft POAs for both the aforementioned adjustors in rebuttal testimony.

In addition, Staff recommended that UNSE update its TCA POA pursuant to discussions it had with Staff and provide a draft in rebuttal testimony.

TRANSMISSION COST ADJUSTOR

Q. Do you wish to address the rebuttal testimony of Company witness Jones?

A. Yes. I would like to discuss Mr. Jones' testimony as it pertains to the TCA POA.

Q. Has the Company provided an updated TCA POA?

A. Yes. Company witness Mr. Jones provided an updated POA for the TCA in his rebuttal testimony. This was submitted as Exhibit CAJ-R-6.

Q. Does Staff believe the updated POA adequately incorporates the intended changes to the methodology used to calculate the TCA?

A. No. Staff was under the impression that the calculations section of the existing POA would be expanded to include the steps used in calculating the TCA as well as the Company's intended changes in methodology. Staff's intent is to provide clear delineation of the proposed changes in methodology so that there is transparency going forward. Staff does not wish to unduly burden the Company but rather to provide a transparent instrument which could be updated as changes occur in the Company's service territory.

Q. How does Staff recommend the Company proceed?

A. Staff would prefer the Company provide an updated POA before the conclusion of this rate proceeding which can be agreed upon. Staff will continue to work with the Company to develop the TCA POA in the hopes that it can be completed in time for a decision.

DEMAND-SIDE MANAGEMENT

Q. Do you wish to address the rebuttal testimony of Company witness Smith?

A. Yes. I would like to discuss Ms. Smith's testimony as it pertains to the DSM POA.

Q. Has the Company provided a DSM POA?

A. No. Staff would reiterate that it would prefer the Company provide a POA before the conclusion of this rate proceeding. Staff is available to work with the Company to develop a DSM POA that is not only consistent with Arizona Administrative Code ("A.A.C.") R12-2-2401 *et seq.*, but also inclusive of other important methodologies which should be transparent, such as performance incentives and how DSM budget items are allocated and treated with regard to rate proceedings.

Q. Are there any other issues pertaining to the DSM adjustor that Staff wishes to address?

A. Yes. Staff would like to respond to the direct testimony of Southwest Energy Efficiency Project ("SWEEP") witness Mr. Schlegel concerning the recommendation to develop a DSM customer-peak-demand-reduction proposal as part of this rate case and the inclusion of $5 million in energy efficiency program funding expensed through base rates.

Q. Does Staff believe additional DSM programs should be considered in this rate case?

A. No. Staff does not believe that this rate case is the most appropriate place to consider new DSM programs. If the outcome of this rate proceeding warrants new DSM programs, Staff would suggest that these DSM programs be proposed in a separate application or in UNSE's next Implementation Plan so that Staff can determine their cost effectiveness.

Q. Does Staff believe the Company should include in any educational program concerning demand charges information regarding potential Energy Efficiency programs?

A. Yes. Staff believes there is definitely a correlation between implementing Energy Efficiency measures and mitigating demand charges. Staff believes that a primary focus of an educational program involving demand charges should be to educate customers on what a demand charge is and how it affects their bill. Therefore, Staff would recommend that energy efficiency be addressed as an essential part of mitigating fees associated with a transition to a three-part rate.

Q. Does Staff agree with SWEEP's proposal to recover funding for DSM programs through base rates?

A. No. Staff prefers that monies associated with Energy Efficiency continue to be collected solely through the DSM adjustor. Under SWEEP's proposal the Commission would have to wait for the Company to file a rate case before it could make changes to any amount being collected through base rates. Although, the Commission could use the DSM adjustor to apply credits and surcharges if budget allotments for DSM programs grew or fell below an amount being collected through base rates; however, Staff prefers the simplicity of the current DSM funding arrangement and would not recommend adopting SWEEPs proposal. Staff prefers for customers to continue to have visibility into the costs on customer bills.

RENEWABLE ENERGY STANDARD AND TARIFF

Q. Do you wish to address the rebuttal testimony of Company witness Tilghman?

A. Yes. I would like to discuss Mr. Tilghman's testimony as it pertains to the REST POA.

Q. Has the Company provided Staff with a REST POA?

A. No. Staff would reiterate that it would prefer the Company provide a POA before the conclusion of this rate proceeding which can be agreed upon. Staff would add that it is available to work with the Company to develop a REST POA that is not only consistent with A.A.C. R14-02-1813 *et seq.*, but also inclusive of other important methodologies which should be transparent, such as how REST budget items are allocated and treated with regard to rate proceedings.

Q. Does this conclude your Surrebuttal testimony?

A. Yes, it does.

EXHIBIT
S-13
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

SUSAN BITTER SMITH
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
DOUG LITTLE
Commissioner
TOM FORESE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. 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 UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

DIRECT

TESTIMONY

OF

CANDREA ALLEN

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 6, 2015

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ATTACHMENTS

EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-15-0142

My testimony addresses UNS Electric, Inc.'s proposed changes to its Rules and Regulations.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Candrea Allen. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Arizona Corporation Commission ("Commission") in the Utilities Division ("Staff") as a Public Utilities Analyst. I provide recommendations on various utility applications to the Commission. I have been employed by the Commission since 2006.

Q. As part of your responsibilities were you assigned to review matters contained in this Docket?

A. Yes.

Q. What is the scope of your testimony in this case?

A. My testimony will be limited to Staff's positions and recommendations relating to UNS Electric, Inc.'s ("UNSE" or "Company") proposed changes to its Rules and Regulations.

DIRECT TESTIMONY

Q. Will you be addressing all of the changes UNSE has proposed in this rate case?

A. No. Many of UNSE's proposed changes are non-substantive and merely clarifications to the current Rules and Regulations. Staff supports these proposed changes.

I will only be addressing what Staff believes to be the substantive changes proposed by UNSE included in the Direct Testimony of Craig Jones and Denise Smith. Staff's recommendations are discussed below, by section, of the Rules and Regulations.

Section 4 – Minimum Customer Information Requirements

Q. What changes are being made to Section 4 of UNSE's Rules and Regulations?

A. UNSE is proposing to add language that would allow the Company to charge its customers when a customer requests consumption history and/or interval data history. The proposed Consumption History Request and Interval History Request charge is also reflected in UNSE's Statement of Charges at $65.00 per hour of customer support.

Q. What are Staff's recommendations regarding the proposed changes to Section 4?

A. The Direct Testimony of Craig Jones indicates that the proposed charge only applies should a customer request this information more than once in a 12-month period. Staff believes, that for clarification, the proposed language should specify that the Consumption History Request and Interval History Request would only apply to those customers who request the information more than once in a 12-month period. Staff recommends inserting the following sentence to Section 4.A.6.:

> **This charge will only apply to customers who request this information more than once in a 12-month period.**

The Statement of Charges should also reflect Staff's recommendation, as a footnote.

In addition, Staff notes that the Direct Testimony of Staff Consultant Howard Solganick will be addressing the proposed consumption history/interval data history charge as part of Statement of Charges in rate design testimony scheduled to be filed on December 9, 2015. Any recommendations included in the testimony of Mr. Solganick regarding the proposed consumption history/interval data history charge that may impact the language included in the Rules and Regulations should also be incorporated.

Section 10-Meter Reading

Q. What changes are being made to Section 10 of UNSE's Rules and Regulations?

A. UNSE's proposed Automated Meter Opt-Out language states that customers may request meters that do not transmit data wirelessly and that UNSE will charge a Special Meter Reading Fee and Automated Meter Opt-Out Set-Up Fee for those customers as specified in its Statement of Charges.

Q. What are Staff's recommendations regarding the proposed changes to Section 10?

A. For those 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 (which would apply to customer self-reads) would be a monthly recurring charge of $26.00. Therefore, Staff recommends that UNSE clarify that customers will only be subject to the Special Meter Reading Fee on a monthly basis should they request to replace an automated meter with a non-transmitting meter or continue the use of a non-transmitting meter.

Staff also recommends that UNSE clarify that the proposed Automated Meter Opt-Out Set-Up Fee of $196.00 will only apply to those customers who request the removal of an automated meter. UNSE has not completed full deployment of automated meters, therefore, customers who currently have a non-transmitting meter would not be subject to the proposed Automated Meter Opt-Out Set-Up Fee. Staff recommends the following be added to Section 10.H.:

> **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 will be a monthly recurring charge. The Automated Meter Opt-Out Set-Up Fee will only apply to those customers who request the removal of an automated meter.**

The Statement of Charges should also reflect Staff's recommendations.

Staff notes that the Direct Testimony of Staff Consultant Howard Solganick will be addressing the amount of the proposed Special Meter Reading Fee and Automated Meter Opt-Out Set-Up Fee as part of Statement of Charges in rate design testimony scheduled to be filed on December 9, 2015. Any recommendations included in the upcoming testimony of Mr. Solganick regarding the proposed Special Meter Reading Fee and Automated Meter Opt-Out Set-Up Fee that may impact the language included in the Rules and Regulations should also be incorporated.

Section 11-Billing and Collection

Q. What changes are being made to Section 11 of the Rules and Regulations?

A. UNSE is proposing two changes to Section 11 that Staff believes need to be clarified.

1) UNSE is proposing to modify Section 11.I.6. Staff does not oppose the proposed change. However, Staff recommends that UNSE add "listed in the Statement of Charges" to the end of the sentence to read:

> **A deferred payment agreement does not relieve the unpaid balance from being assessed a monthly late charge, in accordance with the current late payment fee percentage rate listed in the Statement of Charges.**

Staff believes that UNSE should clarify where the actual rate for the monthly late charge, referenced in this section, can be found.

2) UNSE is proposing to modify Section 11.L.2 by replacing the word "incurred" to "assessed". Staff does not oppose the proposed change. However, for clarification purposes, Staff recommends that UNSE add "by the Company" to the end of the sentence to read:

> **If a collection agency referral is warranted for collection of unpaid final bills, Customer will be responsible for associated collection agency fees assessed by the Company.**

Section 12-Termination of Service

Q. What changes are being made to Section 12 of the Rules and Regulations?

A. UNSE is proposing to add Sub-section 12.H which reads:

> **In the event a Customer provides the Company with documentation certifying that the Customer depends on electricity to power a life-sustaining medical device or if a Customer's medical condition warrants continuous electrical service and the Customer accumulates debt equivalent to a three (3) month bill, in lieu of disconnection of service, the Company may limit the amount of current flowing into the premises to operate medical devices and basic appliances, such as refrigeration, water supply, lighting and small motors in the heating system.**

UNSE states that it would only limit service as a last resort when all other attempts to work with a customer have been exhausted, regarding bill payment status.[1]

Q. What are Staff's recommendations regarding the proposed changes to Section 12?

A. Staff believes that limiting the amount of electricity to a customer that requires electricity to power life-sustaining medical devices or if a customer's medical condition warrants

[1] UNSE response to STF 14.16 (Attachment CA-1)

continuous service could potentially have a significant negative impact on the health of a customer. Staff does not have information about which electricity using devices/equipment (e.g. the actual medical device or an air conditioning unit) would be affected.

Further, UNSE indicates that it currently has approximately 560 customers with a life-sustaining medical device or medical conditions that warrant continuous electrical service and of these only nine accounts have been delinquent for 90 days or more.[2] Staff believes this is an insignificant number of UNSE's total customers and that their medical circumstances could present hazardous and unsafe conditions if service is limited. Therefore, Staff recommends that UNSE's proposed sub-section 12.H not be approved for inclusion in its Rules and Regulations.

SUMMARY OF RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A. Staff makes the following recommendations:

- That UNSE clarify that the consumption history/interval data history charge only applies if a customer requests the information more than once in a 12-month period. The Statement of Charges should also reflect Staff's recommendation.
- That UNSE specify that customers will be subject to the Special Meter Reading Fee on a monthly basis when they request to continue to use a non-transmitting meter or replace an automated meter with an analog meter.
- That UNSE clarify that the Automated Meter Opt-Out Set-Up Fee will only apply to those customers who currently have an automated meter but request that the automated meter be removed and replaced by a non-transmitting meter. Customers who currently have an analog meter would not be subject to the proposed Automated

[2] UNSE response to STF 14.14 (Attachment CA-2)

Meter Opt-Out Set-Up Fee. The Statement of Charges should also reflect Staff's recommendations.

- Staff recommends that UNSE add "listed in the Statement of Charges." to the end of Sub-section 11.I.6.
- Staff recommends that UNSE add "by the Company." to the end of Sub-section 11.L.2

Q. Does this conclude your direct testimony?

A. Yes, it does.

UNS ELECTRIC INC.'S RESPONSE TO STAFF'S FOURTEENTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
September 28, 2015

STF 14.16

Under what circumstances would UNSE not limit electric service to a customer specified under Subsection 12.H. regardless of the customer's bill payment status?

RESPONSE:

UNS Electric views limiting service as a last resort effort, and only after all attempts to work with a customer have been exhausted. Each case would be reviewed individually, and UNS Electric will ensure this measure, when employed, will not present a hazardous or otherwise unsafe condition to those occupying a premise.

RESPONDENT:

Brian Bub

WITNESS:

Denise Smith

UNS ELECTRIC INC.'S RESPONSE TO STAFF'S FOURTEENTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
September 28, 2015

Section 12: Termination of Service

STF 14.14

In how many instances during the past 3 years has UNSE had a customer with a life-sustaining medical device or medical condition that warrants continuous electrical service been delinquent on bill payments for three (or more) months?

RESPONSE:

UNS Electric does not have records to adequately answer the question over the last three years. However, currently, there are approximately 561 active accounts with a life-sustaining medical device or medical condition that warrants continuous electrical service. Of those, nine accounts are in arrears 90 days or more.

RESPONDENT:

Brian Bub

WITNESS:

Denise Smith

EXHIBIT
S-14
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
Commissioner
ANDY TOBIN
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. 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 UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

SURREBUTTAL

TESTIMONY

OF

CANDREA ALLEN

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2016

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EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-15-0142

My surrebuttal testimony addresses the rebuttal testimony of UNS Electric, Inc.'s witness Denise Smith regarding the Company's proposed changes to its Rules and Regulations. Staff makes the following recommendations:

- Staff does not recommend approval of UNSE's proposal to revise Subsection 3.B.1.a. of its Rules and Regulations.
- Staff recommends approval of UNSE's proposed revisions to Staff's initial recommendations regarding Subsections 4.A.6 and 11.L.2.
- Staff recommends approval of UNSE proposed Subsection 12.H except that the language should not apply to customers having a medical device or medical condition. Therefore, Staff recommends that UNSE revise the proposed language in 12.H to specify that customers having a medical device or medical condition would not be eligible to participate in current limitation.
- Staff recommends that UNSE work with Staff to develop a customer agreement for current limitation.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Candrea Allen. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Arizona Corporation Commission ("Commission") in the Utilities Division ("Staff") as a Public Utilities Analyst.

Q. Have you previously filed testimony in this docket?

A. Yes. I filed direct testimony regarding the proposed changes to UNS Electric, Inc.'s ("UNSE" or "Company") Rules and Regulations.

Q. What is the scope of your surrebuttal testimony in this case?

A. My surrebuttal testimony addresses the rebuttal testimony of UNSE witness Denise Smith regarding the Company's Rules and Regulations.

SURREBUTTAL TESTIMONY

Q. Are there any items in the UNSE Rate Case application that you did not address in Direct Testimony that you wish to address now?

A. Yes. Staff inadvertently omitted discussion regarding UNSE's proposed changes to Section 3- ***Establishment of Service Subsection B - Deposits*** of its Rules and Regulations. This was an unintentional oversight.

Q. What changes are being proposed to Section 3 of UNSE's Rules and Regulations?

A. UNSE is proposing to delete language regarding customer deposits from Section 3.B.1.a which currently reads:

> **The Applicant has had service of a comparable nature with the Company within the past two (2) years and was not delinquent in payment *more than* twice during the last twelve (12) consecutive months of service or was not disconnected for nonpayment. [Emphasis added.]**

UNSE is proposing to remove the words ***more than*** from the sentence.

Q. Does Staff agree with UNSE's proposed revision?

A. No. The current language in Subsection 3.B.1.a. of UNSE's Rules and Regulations is the precise language from Arizona Administrative Code ("A.A.C.") R14-2-203.B.1.a. Staff believes that removing the words ***more than*** from UNSE's current language would be inconsistent with A.A.C. R14-2-203.B.1.a. Therefore, Staff does not recommend approval of UNSE's proposed revision to Section 3.

Response to UNSE Rebuttal Testimony

Q. Does Staff agree with the modifications UNSE is proposing to Staff's initial recommendations regarding Subsections 4.A.6 and 11.L.2?

A. Yes. Staff believes that UNSE's proposed modifications to Staff's initial recommendations to Subsections 4.A.6 and 11.L.2 are appropriate and add clarity.

Q. What is UNSE's proposal regarding Subsection 12.H?

A. UNSE is proposing to add Subsection 12.H which reads:

> **In the event a Customer provides the Company with documentation certifying that the Customer depends on electricity to power a life-sustaining medical device or if a Customer's medical condition warrants continuous electrical service and the Customer accumulates debt equivalent to a three (3) month bill, in lieu of disconnection of service, the Company may limit the amount of current flowing into the premises to operate medical devices and basic appliances, such as refrigeration, water supply, lighting and small motors in the heating system.**

Q. Does Staff believe its recommendation regarding UNSE's proposed language in Subsection 12.H needs to be modified for clarification?

A. Yes. According to UNSE witness Denise Smith's rebuttal testimony, the proposed language "...would not necessarily be used only for customers with medical device alerts." Staff believes that its initial recommendation should be modified for clarification regarding whom the proposed language should apply.

Q. What was Staff's recommendation regarding the proposed language in Subsection 12.H?

A. Initially, Staff did not recommend approval of UNSE's proposed language. Staff was, and continues to be, concerned that limiting the amount of electricity to a customer that requires electricity to power life-sustaining medical devises or if a customer's medical condition warrants continuous service could potentially have a significant negative impact on the health of a customer. In addition, as stated in my direct testimony, UNSE has stated that of the approximately 560 customers with a life-sustaining medical device or medical condition that warrant continuous electrical service, only nine of the accounts had been delinquent for 90 days or more, as of September 2015. In response to additional data requests, UNSE indicated that, as of February 14, 2016, there was a total of 555 customers with a life-sustaining medical device or medical condition that warrant continuous electrical service and, of those, 14 accounts had been delinquent for 90 or more days. The total amount in arrears and owed by these 14 accounts as of that date was approximately $4,765.

Based on this information, Staff continues to believe that, though the number of accounts in arrears has increased, this represents an insignificant number of UNSE's total customers and does not believe that UNSE has demonstrated a valid need to implement its proposed current limitation for customers having a medical device or medical condition.

Further, the rebuttal testimony of Denise Smith states that customers with a medical device or medical condition would have their current limited in lieu of service disconnection. However, Staff notes that A.A.C. R14-2-211.A.5. specifies the conditions in which a utility shall not terminate service where the customer has the inability to pay and a) "[t]he customer can establish through medical documentation that, in the opinion of a licensed medical physician, termination would be especially dangerous to the health of a customer or permanent resident residing on the customer's premises, or b) Life supporting equipment used in the home that is dependent on utility service for operation of such apparatus..."

Staff believes that UNSE's proposed language is inconsistent with A.A.C. R14-2-211.A.5 regarding customers having a medical device or medical condition as it pertains to termination of service. Therefore, Staff does not recommend that the proposed language should apply to customers having medical device or medical condition.

Q. What is Staff's recommendation regarding the proposed changes to Subsection 12.H regarding all other UNSE customers?

Staff believes that UNSE's proposed language could apply to all other customers in lieu of disconnection of service. After discussions with UNSE witness Denise Smith, Staff was able to get a more detailed understanding as to how the proposed electricity current limitation would operate. With this additional information, Staff believes that the option to limit the amount of current in lieu of disconnection could be a better option for some customers.

However, Staff believes that UNSE should provide each customer, or customer representative, with a written agreement which details how the current limitation would operate. Staff believes this agreement would ensure that the customer fully understands the specific terms of how the current limitation would operate. The agreement should include, at a minimum, the following information:

- Explanation of what current limitation is;
- Specification that customers or permanent resident at the customer's premises identified as having a medical device or medical condition or are not eligible for current limitation;
- How current limitation operates (i.e., if a device is placed on the meter, a new meter setting on a current meter, etc.);
- The appliance(s) and/or fixture(s) that would and would not continue to operate normally with the current limitation;
- Explanation of what happens to the appliance(s)/fixture(s) should the set current amount be exceeded;
- Actions the customer is required to take should the set current amount be exceeded (i.e., resetting of a breaker box, resetting the device on the meter, etc.);

- A statement indicating that the current limitation would continue until the customer becomes current on bill payments (as determined by the length of a deferred payment plan); and
- Notification that the customer is required to update any changes regarding electricity needs.

Each individual item included in the agreement should be initialed by the customer, or customer representative, to acknowledge being read and understood, and the agreement should be signed and dated by the customer, or customer representative. Staff recommends that the Company work with Staff to develop the customer agreement.

SUMMARY OF RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A. Staff makes the following recommendations:

- Staff does not recommend approval of UNSE's proposal to revise Subsection 3.B.1.a. of its Rules and Regulations.
- Staff recommends approval of UNSE's proposed revisions to Staff's initial recommendations regarding Subsections 4.A.6 and 11.L.2.
- Staff recommends approval of UNSE's proposed language to Subsection 12.H except for customers having a medical device or medical condition.
- Staff recommends that UNSE revise its proposed language to Subsection 12.H to exclude customers having a medical device or medical condition.
- Staff recommends that UNSE work with Staff to develop a customer agreement for current limitation.

- Staff recommends that UNSE work with Staff to develop a customer agreement for current limitation.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
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Commissioner
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ANDY TOBIN
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IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. 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 UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

SURREBUTTAL

TESTIMONY

OF

YUE LIU

PUBLIC UTILITIES ANALYST III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2016

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EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-15-0142

My Surrebuttal Testimony will address the estimated financial net savings or net costs in purchasing or leasing a rooftop solar system from a typical UNS Electric, Inc. ("UNSE" or "Company") residential customer's perspective. I provide a comparison of the net savings and net costs for a customer considering solar based on four different rate designs, namely, the Company's current effective Residential Service rate schedule ("Existing RES-01"), the Company's proposed Residential Service Demand rate schedule in its Application ("Company Original Proposed RES-01 Demand"), the Company's proposed Residential Service Demand Time-of-Use rate schedule in its Application ("Company Original Proposed RES-01 TOU Demand"), and the revised Residential Service Demand Time-of-Use rate schedule in the Company's Rebuttal Testimony ("Company Rebuttal RES-01 TOU Demand").

By modeling the bill savings under four different rate designs, Staff intends to demonstrate that with the Company Rebuttal RES-01 TOU Demand customers can achieve a reasonable Internal Rate of Return ("IRR") when purchasing a rooftop solar system, which makes it a financially feasible investment. With an annual future utility rate escalation of 2.5 percent, the IRRs can reach 8.10 percent and 7.64 percent, respectively, for an Average Customer and a Large Customer. This level of IRR is higher than the annual return on a 10-year Treasury Bond ("10-year T-Bond"), which is generally accepted as the discount rate for long-term investment. The IRRs are slightly higher than the recent 10-year (2006-2015) average annual return on the Standard & Poor's 500 ("S&P 500"). In addition, the IRRs are higher than mortgage rates for all three electric escalation scenarios shown in this testimony. My preliminary analysis shows that purchasing a rooftop solar system would still be an economically viable choice with the adoption of the Company Rebuttal RES-01 TOU Demand rate schedule. Nevertheless, the pace of rooftop solar installations would be expected to be reduced, at least temporarily, if Company Rebuttal RES-01 TOU Demand is adopted, all else being constant.

INTRODUCTION

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

A. My name is Yue Liu. I am a Public Utilities Analyst III employed by the Arizona Corporation Commission ("Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Please describe your educational background and professional experience.

A. In 2013, I graduated with high distinction from the University of Minnesota, receiving a Bachelor of Arts degree in economics, mathematics and statistics. In 2014, after working as an investment-banking analyst for one year, I enrolled in the graduate program in statistics at the University of California Berkeley and received a Master of Arts degree in 2015. Before joining the Commission in December 2015, I worked on several research projects of various disciplines as a statistical consultant, offering clients advisory services on experimental designs, sampling methodologies, data analytics and statistical inferences.

Q. Briefly describe your responsibilities as a Public Utilities Analyst III.

A. In my capacity as a Public Utilities Analyst III, I have been assigned to analyze and provide recommendations to the Commission on assigned cases. This is my first proceeding as a Public Utilities Analyst with the Commission.

Q. Did you file Direct Testimony in this proceeding?

A. No.

Q. What is the scope of your testimony in this case?

A. I provide estimates of financial net savings and net costs in purchasing or leasing a rooftop solar system from the perspective of a typical UNS Electric, Inc. ("UNSE" or "Company") residential customer using a bill and solar cost estimation model I sponsor herein. Among other things, I provide a comparison of the net savings and net costs for a customer considering solar based on four different rate designs, namely, the Company's current effective Residential Service rate schedule ("Existing RES-01"), the Company's proposed Residential Service Demand rate schedule in its Application ("Company Original Proposed RES-01 Demand"), the Company's proposed Residential Service Demand Time-of-Use rate schedule in its Application ("Company Original Proposed RES-01 TOU Demand"), and the revised Residential Service Demand Time-of-Use rate schedule in the Company's Rebuttal Testimony[1] ("Company Rebuttal RES-01 TOU Demand"). I also performed a sensitivity analysis to examine the impacts of potential new solar incentives on the cost effectiveness of Distributed Generation ("DG") solar for residential customers.

Q. Have you reviewed direct and rebuttal testimony submitted by the various parties in this case as it relates to the subject matter of your Surrebuttal Testimony?

A. Yes. My reviews included testimony from DG solar industry representatives and associations which intervened in this case.

The DG solar industry interveners are opposed to demand kW rates due, in part, to concern for the future viability of their DG solar business model(s) which appear to now be at a crossroads as electric utilities such as UNSE propose significant rate design changes to address their various concerns. However, the DG solar industry has not introduced into this case any of its business models, yet it is well-known that residential customers are provided with a detailed electric rate savings analysis that is compared to the various cost of purchase or leasing DG solar at the time a customer considers a DG solar purchase. To address these concerns,

[1] Jones, Rebuttal Exhibit CAJ-R-4, page 4 of 7.

Staff witness, Mr. Broderick, tasked me with preparation of the analysis I discuss in my testimony.

BILL ESTIMATION AND SOLAR COST MODEL AND ASSUMPTIONS

Q. How was the bill estimation and solar cost model established?

A. On January 6, 2016, Staff issued a data request to Arizona Public Service Company ("APS") and The Alliance for Solar Choice ("TASC") requesting a spreadsheet template which quantitatively captures from a residential customer's perspective the typical financial net savings or net costs of purchasing or leasing a rooftop solar system. APS responded with an initial model including relevant inputs and assumptions. TASC objected and did not provide any analysis at that time. Staff then forwarded the APS model to both UNSE and TASC requested their reactions and suggestions for improving the model.

The final model used in Staff's surrebuttal testimony was based on the initial APS model and augmented by relevant revisions and improvements from incorporation of UNSE and TASC input and Staff's internal review and best judgement. Staff is grateful to APS, UNSE and TASC for their thoughtful and useful assistance. The raw information regarding implementation of three part rates provided by APS and UNSE generally showed DG solar as cost effective for customers; whereas, TASC estimated DG solar as less cost effective. UNSE provided its input on February 1, 2016 and TASC on February 5, 2016.

The model used here should be viewed as Staff's model for which it is responsible. Staff is confident in the relative DG solar cost effectiveness demonstrated under the various rate options presented herein. Staff acknowledges there is uncertainty concerning the input assumptions and, therefore, in the absolute values of the resulting estimations.

Q. Has Staff used such an approach or model before?

A. No. And, we are not aware of it being used by any other state. However, we believe it adds an important new dimension to the analysis of rooftop solar and financial considerations of customers who are or may become DG customers. We are continuing to evaluate the model and will on an ongoing basis look for any ways the model can be improved.

Q. What are the key assumptions used in modeling the net savings or net costs in purchasing or leasing a rooftop solar system?

A. The initial assumptions include the 1) solar system size (kW-DC); 2) solar system conversion factor (kWh-AC/kW-DC); 3) seasonal shaping of solar generation; 4) solar off-setting load at time of generation; 5) a typical residential customer kWh and kW before solar by season; 6) related taxes and fees; 7) solar purchase cost ($/kW-DC); and 8) applicable federal and state investment credits. The numerical values of those assumptions are listed in Schedule YL-1.

Q. Please discuss each key necessary assumption starting with the customer's solar system size (kW-DC).

A. For this assumption, Staff utilized UNSE's response to Staff data requests[2] for the average residential customer and Schedule H-4, Page 1 of 22, data for the large residential customer assuming a 90 percent offset of a customer's energy. This means the customer's DG solar system generates 90 percent of its energy requirement. UNSE assumed 100 percent and TASC assumed 80 percent. Staff selected the midpoint of 90 percent, resulting in 4.77 kW and 6.86 kW system sizes, respectively, for average and large customers.

[2] Staff to UNSE 29.1

Q. What is the solar system conversion factor (kWh-AC/kW-DC)?

A. That assumption represents the energy kWh generation estimate per kW. UNSE provided 1,800 kWh annually per one kW. UNSE provided 1,800 based on Tucson and TASC provided 1,698 based on Flagstaff using the National Renewable Energy Laboratory's ("NREL") System Advisor Model. This assumption is also used in the formula for the customer's solar system size as described above. Staff selected the UNSE provided amount based on the NREL Tucson area data.

Q. Why did you use NREL's Tucson area data?

A. NREL has data covering several areas in Arizona. In responses to Staff data requests, the Company (Staff to UNSE 29.1) and TASC (email response) used Tucson and Flagstaff area data, respectively. Flagstaff is on a similar latitude as the Company's major service territory (Kingman and Lake Havasu City). However, Flagstaff has a much higher elevation (6,910 feet) compared to Kingman (3,333 feet), Lake Havasu City (735 feet) and Nogales (3,832 feet). Thus, the electricity consumption and weather characteristics are quite different in Flagstaff compared to the Company's service territory. Flagstaff would have higher winter electricity consumption (for customers with electric heating) and lower summer consumption (little to no air conditioning requirement) as compared to Tucson which Staff concluded would introduce a potential for bias as a key characteristic of DG solar is the carryover of banked electricity into higher tariff summer periods, at least under Staff's analyses of scenarios which continue the existing net metering. Staff concluded the bias would be in the direction of reducing the financial attractiveness of DG solar to residential customers. Tucson has an elevation of 2,643 feet and its latitude is between Nogales and Mohave County, which makes it a better proxy for the Company's service territory than Flagstaff. Recently, Staff became aware that NREL has useful data for other Arizona communities[3], but time did not permit its use in this surrebuttal testimony.

Q. What did you assume for seasonal shaping of solar generation?

A. Seasonal shaping is each season's average monthly DG solar generation as a percentage of the monthly average DG solar generation. UNSE provided a 105 percent summer to annual solar generation percentage and a 95 percent winter to annual solar generation percentage. TASC provided 110 percent and 90 percent, respectively, for summer and winter. Staff selected the UNSE provided percentages.

Q. What is solar off-setting load at time of generation?

A. Solar off-setting load at time of generation represents the percentage of a customer's solar production which is self-consumed at the time of generation. The balance, then, is exported. UNSE provided a summer percentage of 44 percent and winter percentage of 37 percent. TASC provided 44 percent and 34 percent, respectively. Staff selected UNSE's assumption. Stated alternatively, UNSE assumed that 56 percent of solar generation in summer is exported and 63 percent is exported in winter. This assumption is obviously important to the estimated value of solar exports in the various tariff scenarios.

Q. What is customer load before solar by season?

A. This is the UNSE provided customer load profile data for the average customer. Staff pro-rata scaled this data for the large customer.

[3] Others include Phoenix, Scottsdale, Kingman, Prescott, and etc.

Q. What is On-peak solar generation?

A. Of the total solar generation, this assumption represents the percentage occurring by season for the On-peak tariff periods in the tariff analyses. UNSE provided 22 percent On-peak and 5 percent On-peak for summer and winter, respectively. TASC provided similar figures, which are 20 percent and 7 percent, respectively. Staff selected the UNSE provided percentages.

Q. What is the solar purchase cost assumption ($/kW-DC)?

A. This assumption is the installed purchase price to the customer. UNSE provided a cost of $2,500 per kW and TASC provided $3,000 per kW. Staff selected $2,750 as a midpoint assumption.

Q. What are the taxes, fees and investment tax credit assumptions?

A. These assumptions relate to applicable avoidable taxes on electric bills and applicable investment tax credits. UNSE provided 10 percent as the percentage of taxes and government fees. TASC provided 0.87 percent. Staff selected the UNSE provided percentage. All parties agreed on the assumptions on federal investment tax credit and Arizona residential solar tax credit provided in Schedule YL-1.

Q. Please provide more information on the two types of residential customers examined in your analyses as depicted in YL-2.

A. Two types of customers are used in the bill saving model, an Average Customer and a Large Customer. An Average Customer has a pre-DG solar monthly kWh usage of 795, which is the mean monthly kWh usage based on a sample of 2,309 UNSE non-DG residential customers. A Large Customer has a pre-DG solar monthly kWh usage of 1,144, which is the "Large Customer" monthly kWh defined in Schedule H-4 of the Company's Application for customers under the existing RES-01. Other characteristics of a Large Customer are adjusted proportionally to those of an Average Customer in the model. The list of the numeric values is shown in Schedule YL-2. Large Customers are modeled because the Company indicated that customers who installed DG tend to have higher consumption on average.

Q. Lastly, what assumptions are made on Net Energy Metering (NEM)?

A. Under the Existing RES-01 and Company Rebuttal RES-01 TOU Demand, the current effective NEM is assumed, with banking and rollover for excess generation. For modeling purposes, the accumulated excess generation is represented as an average credit spread over all months, and the excess generation banked during the winter months is assumed to evenly offset summer months' energy usage. The year-end balance of excess generation is paid out to customers at the Company's current effective Market Cost of Comparable Conventional Generation ("MCCCG") of $0.03003 per kWh used in Existing RES-01 and $0.03697 per kWh used in Company Rebuttal RES-01 TOU Demand.

Under the Company Original Proposed RES-01 Demand and Company Original Proposed RES-01 TOU Demand, the proposed NEM alternative in the Company's Application is assumed. With the proposed NEM alternative, no banking or rollover for excess generation is allowed, and all exported electricity from a customer to the Company is paid out each month to the customer at a rate of $0.00584 per kWh.

RESULTS AND COMPARISON

Q. What evaluation measures did you select for purchasing a rooftop solar system?

A. In order to evaluate the purchasing option, the simple payback and the Internal Rate of Return ("IRR") measures were selected. The purpose of using those two measures is to capture the total financial impact of purchasing a rooftop solar system, by evaluating bill savings together with system capital cost recovery.

Q. What are the resulting simple paybacks?

A. Simple payback is a straightforward measure of how many years a customer needs to recover the initial cost of purchasing a rooftop solar system through bill savings. Table 1 below summarizes the resulting simple paybacks for an Average Customer and a Large Customer.

	Simple Payback (Years)	
	Average Customer	Large Customer
Existing RES-01	9.2	9.2
Company Original Proposed RES-01 Demand	14.4	14.9
Company Original Proposed RES-01 TOU Demand	15.0	15.5
Company Rebuttal RES-01 TOU Demand	11.5	11.9

Table 1: Resulting Simple Paybacks

The results suggest that, under the Existing RES-01, both the Average Customer and Large Customer can achieve a better simple payback. However, with the Company Rebuttal RES-01 TOU Demand, both customers have effective improvement in terms of simple payback, as compared to the Company Original Proposed RES-01 Demand and Company Original Proposed RES-01 Demand.

Q. What is the formula of the IRR?

A. The IRR is a financial metric used to evaluate the profitability of any potential investments. The IRR is a discount rate that makes the net present value ("NPV") of all cash flows from a particular investment equal to zero. In the bill saving model, the IRR is calculated based on the formula below:

$$NPV = 0 = -C_0 + \frac{S_1}{1+IRR} + \frac{S_2}{(1+IRR)^2} + \cdots + \frac{S_{20}}{(1+IRR)^{20}},$$

where C_0 is the total initial cost of purchasing the rooftop solar system, and S_1, S_2, …, S_{20} are the annual bill savings during the period of year 1, 2, …, 20 after the rooftop solar system is installed.

Q. Why is the IRR used to evaluate a customer's investment decision in purchasing the rooftop solar system?

A. Staff is using the IRR because, unlike the NPV, it does not make a numerical assumption regarding discount rate. Given different perspectives on discount rates for various customers, using the IRR simplifies the evaluation. Generally speaking, the higher an investment's IRR, the more desirable it is to undertake the investment from the customer's perspective. Thus, the IRR can be used to rank multiple potential investments. In the bill saving model, the IRR provides an effective comparison for the financial feasibility of investing in a rooftop solar system under the four rate designs. Moreover, the IRR can also be compared against the prevailing rate of return in the securities market or accepted discount rate which are reference points for customers. For a customer considering an investment in a rooftop solar system, if the IRR for the investment is higher than his/her (publicly unknown) but accepted discount rate, the investment is economically viable.

Q. Are there additional assumptions in calculating the IRR?

A. Yes. An annual DG solar degradation rate of 0.25 percent and a lifespan of 20 years are assumed for the solar system. Moreover, in order to perform a sensitivity analysis, three levels of annual future utility rate escalation are assumed: 0 percent, 1.5 percent and 2.5 percent.

Q. How does the change of those assumptions affect the resulting IRRs?

A. The change of assumptions on annual degradation rate and annual future utility rate escalation will affect the numeric values of the resulting IRRs. However, the relative ranking among the four rate designs should be unchanged and accurate, which is the reason why the IRR is used here as an evaluation measure. Table 2 and Table 3 illustrate the unchanged rankings among the four rate designs with the various assumptions of utility rate escalation.

Q. What are the resulting IRRs for an Average Customer?

A. The resulting IRRs for an Average Customer under the four rate designs with three levels of utility rate escalation are summarized in Table 2 below:

	IRR (%)		
Utility Rate Escalation	0.00%	1.50%	2.50%
Existing RES-01	8.72%	10.14%	11.09%
Company Original Proposed RES-01 Demand	3.13%	4.52%	5.44%
Company Original Proposed RES-01 TOU Demand	2.71%	4.09%	5.01%
Company Rebuttal RES-01 TOU Demand	5.76%	7.16%	8.10%

Table 2: Resulting IRRs for an Average Customer

From the table above, it can be observed that an Average Customer is better off under the Company Rebuttal RES-01 TOU Demand compared to the Company Original Proposed RES-01 Demand and Company Original Proposed RES-01 TOU Demand. Even though the IRR is lower compared to the IRR under the Existing RES-01, with the Company Rebuttal RES-01 TOU Demand purchasing a rooftop solar system is still an economically viable investment, especially when a high utility rate escalation is expected.

Q. What are the resulting IRRs for a Large Customer?

A. The resulting IRRs for a Large Customer under the four rate designs with three levels of utility rate escalation are summarized in Table 3 below:

	IRR (%)		
Utility Rate Escalation	0.00%	1.50%	2.50%
Existing RES-01	8.69%	10.11%	11.06%
Company Original Proposed RES-01 Demand	2.74%	4.12%	5.03%

Company Original Proposed RES-01 TOU Demand	2.32%	3.70%	4.61%
Company Rebuttal RES-01 TOU Demand	5.31%	6.71%	7.64%

Table 3: Resulting IRRs for a Large Customer

The results illustrated in the above table for a Large Customer are similar to the results shown in Table 2 for an Average Customer.

Q. Can you provide a prevailing rate of return in the securities market or a generally accepted discount rate for comparison purposes?

A. Yes. The Standard & Poor's 500 ("S&P 500") is an American stock market index based on the market capitalizations of 500 large companies with common stock listed on the NYSE or NASDAQ. The S&P 500 has a diverse constituency and is widely considered as one of the best representations of the U.S. stock market and the U.S. economy. Therefore, the return on the S&P 500 can be used as a prevailing rate of return in the securities market. In addition, the returns on a 3-month Treasury Bill ("3-month T-Bill") and a 10-year Treasury Bond ("10-year T-Bond") are generally accepted discount rates for long term and short term investments, respectively. Table 4 below summarizes the geometric averages of the annual returns on the S&P 500, the 3-month T-Bill and the 10-year T-Bond for three different time periods. The raw data of annual returns during 1928 - 2015 was retrieved from Dr. Aswath Damodaran's online database (http://pages.stern.nyu.edu/~adamodar/). Dr. Damodaran is a Professor of Finance at the Stern School of Business at New York University. The raw data is listed in Schedule YL-2.

	S&P 500	3-month T-Bill	10-year T-Bond
1928-2015	9.50%	3.45%	4.96%
1966-2015	9.61%	4.92%	6.71%
2006-2015	7.25%	1.14%	4.71%

Table 4: Geometric Averages of the Annual Returns

Q. Are there any other prevailing discount rates that can be used for comparison purposes?

A. Mortgage rate is another widely used prevailing discount rate. The Primary Mortgage Market Survey ("PMMS") results provided by Freddie Mac are presented in this surrebuttal testimony. Through the PMMS, Freddie Mac surveys lenders each week on the rates, fees and points for the most popular mortgage products. Three types of mortgage products will be shown, namely 30-Year Fixed-Rate Mortgages ("30-Yr FRM"), 15-Year Fixed-Rate Mortgages ("15-Yr FRM") and 5-Year Adjustable-Rate Mortgages ("5/1-Yr ARM"). Table 5 below lists the average rates of these three mortgage products for 2005-2015.

	Mortgage Products		
	30-Yr FRM	15-Yr FRM	5/1-Yr ARM
Average Rate (2005-2015)	4.95%	4.35%	4.25%

Table 5: Average Rates of Three Mortgage Products

Q. Please summarize your findings from your analysis.

A. With an annual future utility rate escalation of 2.5 percent, the IRRs can reach 8.10 percent and 7.64 percent, respectively, for an Average Customer and a Large Customer. This level of IRR is relatively higher than the annual return on a 10-year T-Bond, which is generally accepted as the discount rate for long-term investment. The IRRs are slightly higher than the recent 10-year (2006-2015) average annual return on the S&P 500. In addition, the IRRs are higher than mortgage rates for all three electric escalation scenarios. Therefore, purchasing a rooftop solar system would still be an economically viable choice even with the adoption of Company Rebuttal RES-01 TOU Demand. Nevertheless, the pace of rooftop solar installations would be expected to be reduced, at least temporarily, if Company Rebuttal RES-01 TOU Demand is adopted, all else being constant.

Q. Please explain the difference in the resulting IRRs under the Existing RES-01 and the Company Rebuttal RES-01 TOU Demand.

A. With the same assumptions of rooftop solar system cost, degradation rate and annual future utility rate escalation, the difference in the resulting IRRs under the above-mentioned two rate designs is mainly due to the variation in the annual bill savings. Table 6 below summarizes the monthly average saving results under the two rate designs for both an Average Customer and a Large Customer.

		Monthly Average Bills			
		Before Solar	After Solar	Credit for Excess Generation	Savings
Average Customer	Existing RES-01	$93.13	$18.64	$0	$74.49
	Company Rebuttal RES-01 TOU Demand	$108.37	$49.61	$0.67	$59.43
Large Customer	Existing RES-01	$132.88	$21.96	$0	$110.92
	Company Rebuttal RES-01 TOU Demand	$148.74	$64.24	$0.98	$85.48

Table 6: Monthly Average Savings Summary

From Table 6, we can observe that, for an Average Customer, the amount of monthly average savings under the Company Rebuttal RES-01 TOU Demand is $15.06 lower than that under the Existing RES-01. Moreover, the reduction in monthly average savings is $25.44 for a Large Customer. In addition, the monthly Basic Service Charge is $10 and $15 under the Existing RES-01 and the Company Rebuttal RES-01 TOU Demand, respectively. This $5 increase in

Basic Service Charge would be applied to all residential customers, so it has been excluded from the reduction in monthly average savings. Therefore, the reduction in monthly average savings is $10.06 and $20.44, respectively, for an Average Customer and a Large Customer. The reduction represents 20.28 percent and 31.82 percent of the monthly after-solar average bill under the Company Rebuttal RES-01 TOU Demand for an Average and a Large Customer, respectively.

Q. What is the impact on the resulting simple paybacks or IRRs under the Company Rebuttal RES-01 TOU Demand if new solar incentives are temporarily offered to residential customers?

A. With solar incentives, the initial cost of purchasing a rooftop solar system will be reduced for a residential customer. The initial cost plays a very critical role in calculating simple payback and the IRR as suggested by the formulas. Thus with lower initial cost, the resulting simple paybacks and the IRRs will improve significantly. In order to evaluate those impacts quantitatively, a sensitivity analysis is performed to capture the impacts with different levels of solar incentives. With the assumptions of 0.25 percent annual degradation rate and 2.5 percent annual future utility rate escalation, the resulting simple paybacks and IRRs under the Company Rebuttal RES-01 TOU Demand for different levels of solar incentives are summarized in Table 7 below.

		Solar Incentives				
		5%	10%	15%	20%	25%
Average Customer	Simple Paybacks (Years)	10.6	9.6	8.7	7.8	6.9
	IRR	9.16%	10.38%	11.80%	13.48%	15.52%
Large Customer	Simple Paybacks (Years)	11.0	10.1	9.1	8.2	7.3
	IRR	8.64%	9.78%	11.10%	12.65%	14.51%

Table 7: Resulting Simple Paybacks and IRRs with Different Levels of Solar Incentives

It can be observed from Table 7 that the solar incentives offer both Average Customer and Large Customer with shorter simple paybacks and greater IRRs. Moreover, with 15 percent solar incentives, both customers can achieve slightly better simple payback and IRR compared to those under the Existing RES-01.

Q. What are the net payoffs under the four rate designs if a customer chooses to lease a rooftop solar system?

A. $0.09/kWh is assumed as the rooftop solar system lease rate, and all parties agreed on this assumption. The monthly average net payoffs under the four rate designs for both an Average Customer and a Large Customer are summarized in Table 8 below. The parentheses in the table indicate a net loss.

	Monthly Average Net Payoff	
	Average Customer	Large Customer
Existing RES-01	$ 10.10	$ 18.26
Company Original Proposed RES-01 Demand	$ (17.00)	$ (24.45)
Company Original Proposed RES-01 TOU Demand	$ (18.80)	$ (27.07)
Company Rebuttal RES-01 TOU Demand	$ (4.97)	$ (7.18)

Table 8: Monthly Average Net Payoffs for Leasing

Q. Please summarize your findings from the modeling of the net payoffs for leasing a rooftop solar system.

A. As Table 8 suggests, leasing a rooftop solar system is an economically viable option only under the Existing RES-01 for both customers. However, those resulting net payoffs are based on the assumption of zero utility rate escalation. With an assumption of 2.5 percent annual future utility rate escalation, under the Company Rebuttal RES-01 TOU Demand, both customers would start to have positive net payoffs in the fifth year after they lease a rooftop solar system. In order to further evaluate the leasing option for a residential customer under the Company Rebuttal RES-01 TOU Demand, the NPV is analyzed to reflect the overall payoffs. In these calculations a 20-year leasing term is assumed and, moreover, a sensitivity analysis is performed to illustrate the NPVs under different assumptions of discount rate. Table 9 below shows the resulting NPVs.

	NPV	
Discount Rate	4.71%	7.20%
Average Customer	$1,335.07	$922.52
Large Customer	$1,915.60	$1,323.05

Table 9: Resulting NPVs under the Company Rebuttal RES-01 TOU Demand

The resulting NPVs in Table 9 suggest both Average Customer and Large Customer can achieve positive NPVs under different assumptions of discount rate. Thus, leasing a rooftop solar system could still be economically viable under the Company Rebuttal RES-01 TOU Demand in the long haul for residential customers.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes, it does.

Key Assumptions

Solar system Size (kW-DC)	
Average Customer	4.77
Large Customer	6.86
Solar system conversion factor (kWh-AC/kW-DC)	1800 (south orientation)
Seasonal shaping of solar generation	
Summer	105% of monthly average
Winter	95% of monthly average
Solar off-setting load at time of generation	
Summer	44% of total solar kWh
Winter	37% of total solar kWh
Customer load before solar by season	See Schedule YL-2
On-peak solar generation	
Summer	22% of total solar kWh
Winter	5% of total solar kWh
Customer on-peak load before solar	
Summer	24% of total kWh
Winter	26% of total kWh
Taxes and government fees	10%
Solar purchase cost ($/kW-DC)	2,750
Federal investment tax credit	30%
Arizona residential solar tax credit	$1,000

Customer Profiles

	Average Customer	Large Customer
Monthly kWh	795	1,144
Solar system size kW-DC	4.77	6.86
Monthly kWh - Summer	935	1,345
Monthly kWh - Winter	665	943
On-peak kW - Summer	4.13	6
On-peak kW - Winter	3.34	4.81
On-peak kW offset - Summer	0.13	0.19
On-peak kW offset - Winter	0	0

Raw Data of Annual Returns

	Annual Returns on Investments in		
Year	*S&P 500*	*3-month T-Bill*	*10-year T-Bond*
1928	43.81%	3.08%	0.84%
1929	-8.30%	3.16%	4.20%
1930	-25.12%	4.55%	4.54%
1931	-43.84%	2.31%	-2.56%
1932	-8.64%	1.07%	8.79%
1933	49.98%	0.96%	1.86%
1934	-1.19%	0.32%	7.96%
1935	46.74%	0.18%	4.47%
1936	31.94%	0.17%	5.02%
1937	-35.34%	0.30%	1.38%
1938	29.28%	0.08%	4.21%
1939	-1.10%	0.04%	4.41%
1940	-10.67%	0.03%	5.40%
1941	-12.77%	0.08%	-2.02%
1942	19.17%	0.34%	2.29%
1943	25.06%	0.38%	2.49%
1944	19.03%	0.38%	2.58%
1945	35.82%	0.38%	3.80%
1946	-8.43%	0.38%	3.13%
1947	5.20%	0.57%	0.92%
1948	5.70%	1.02%	1.95%
1949	18.30%	1.10%	4.66%
1950	30.81%	1.17%	0.43%
1951	23.68%	1.48%	-0.30%
1952	18.15%	1.67%	2.27%
1953	-1.21%	1.89%	4.14%
1954	52.56%	0.96%	3.29%
1955	32.60%	1.66%	-1.34%
1956	7.44%	2.56%	-2.26%
1957	-10.46%	3.23%	6.80%
1958	43.72%	1.78%	-2.10%
1959	12.06%	3.26%	-2.65%

1960	0.34%	3.05%	11.64%
1961	26.64%	2.27%	2.06%
1962	-8.81%	2.78%	5.69%
1963	22.61%	3.11%	1.68%
1964	16.42%	3.51%	3.73%
1965	12.40%	3.90%	0.72%
1966	-9.97%	4.84%	2.91%
1967	23.80%	4.33%	-1.58%
1968	10.81%	5.26%	3.27%
1969	-8.24%	6.56%	-5.01%
1970	3.56%	6.69%	16.75%
1971	14.22%	4.54%	9.79%
1972	18.76%	3.95%	2.82%
1973	-14.31%	6.73%	3.66%
1974	-25.90%	7.78%	1.99%
1975	37.00%	5.99%	3.61%
1976	23.83%	4.97%	15.98%
1977	-6.98%	5.13%	1.29%
1978	6.51%	6.93%	-0.78%
1979	18.52%	9.94%	0.67%
1980	31.74%	11.22%	-2.99%
1981	-4.70%	14.30%	8.20%
1982	20.42%	11.01%	32.81%
1983	22.34%	8.45%	3.20%
1984	6.15%	9.61%	13.73%
1985	31.24%	7.49%	25.71%
1986	18.49%	6.04%	24.28%
1987	5.81%	5.72%	-4.96%
1988	16.54%	6.45%	8.22%
1989	31.48%	8.11%	17.69%
1990	-3.06%	7.55%	6.24%
1991	30.23%	5.61%	15.00%
1992	7.49%	3.41%	9.36%
1993	9.97%	2.98%	14.21%
1994	1.33%	3.99%	-8.04%
1995	37.20%	5.52%	23.48%
1996	22.68%	5.02%	1.43%
1997	33.10%	5.05%	9.94%

1998	28. 34%	4. 73%	14. 92%
1999	20. 89%	4. 51%	-8. 25%
2000	-9. 03%	5. 76%	16. 66%
2001	-11. 85%	3. 67%	5. 57%
2002	-21. 97%	1. 66%	15. 12%
2003	28. 36%	1. 03%	0. 38%
2004	10. 74%	1. 23%	4. 49%
2005	4. 83%	3. 01%	2. 87%
2006	15. 61%	4. 68%	1. 96%
2007	5. 48%	4. 64%	10. 21%
2008	-36. 55%	1. 59%	20. 10%
2009	25. 94%	0. 14%	-11. 12%
2010	14. 82%	0. 13%	8. 46%
2011	2. 10%	0. 03%	16. 04%
2012	15. 89%	0. 05%	2. 97%
2013	32. 15%	0. 07%	-9. 10%
2014	13. 52%	0. 05%	10. 75%
2015	1. 36%	0. 21%	1. 28%

EXHIBIT
S-16
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

SUSAN BITTER SMITH
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
DOUG LITTLE
Commissioner
TOM FORESE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. 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 UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

DIRECT

RATE DESIGN TESTIMONY

OF

THOMAS M. BRODERICK

DIRECTOR

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

DECEMBER 9, 2015

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APPENDICES

EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-15-0142

Among its rate design related recommendations, Staff recommends that UNS Electric, Inc.'s ("UNSE" or "Company") residential and small general service class rate designs be modernized in a timely rate migration transition process from a two-part rate (monthly minimum and energy charge) to a three-part tariff (monthly minimum, energy charge and demand charge), including a time-of-use energy kWh rate differentiation. A three-part rate makes significant progress toward addressing essentially all of the issues presented by the difficult transition to new distributed generation ("DG") technologies now underway. Residential and small general service customers should be required to migrate to this new rate, but certain specific and definable vulnerable groups could be exempted.

While Staff appreciates the Company's proposal to rely on a Renewable Credit Rate to compensate customers for excess DG, Staff does not presently endorse the Company's proposal. Staff has a number of concerns it would like the Company to address. Staff notes that Commission Docket No. E-00000J-14-0023, which is designed to examine the value and cost of solar, will provide useful and timely information for the parties to consider in this rate case. Therefore, for the time being, Staff does not propose changes to the existing net metering tariff or waivers of the net metering rules, but Staff may update its position in surrebuttal testimony or later at the hearing in this case.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Thomas M. Broderick. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Arizona Corporation Commission ("Commission") as Director of the Utilities Division ("Staff"). My qualifications are provided in Appendix TMB-1.

Q. What is the subject matter of your testimony?

A. My testimony addresses some of Staff's policy recommendations for the residential and small general service class rate designs for UNS Electric Inc. ("UNSE" or "Company"). It also addresses net metering and the related topic of the value and cost of distributed generation ("DG") for all customer classes. The direct rate design testimony of Staff consultant, Mr. Howard Solganick, provides additional and more specific Staff rate design related recommendations.

STAFF'S RESIDENTIAL & SMALL GENERAL SERVICE RATE DESIGN POLICY RECOMMENDATIONS

Q. Why is it Staff's primary recommendation for UNSE to migrate all of its residential and small general service customers to a new tariff design that includes a demand charge component as soon as a transition can be completed?

A. For a variety of reasons, Staff recommends UNSE undertake a revenue neutral process to migrate all of its residential and small general service customers to a new tariff which includes a demand charge within a three-part tariff with time-of-use energy kWh charge differentiation. A three-part tariff is comprised of a monthly customer charge, a per kilowatt-hour ("kWh") energy charge(s) and per kilowatt ("kW") demand charge(s). Staff believes that a three-part rate structure is more reflective of UNSE's costs of service and the sooner a migration occurs the better for all.

A three-part rate design better informs customers who are considering adopting new technologies, including DG, about the utility bill impact of their technology choices prior to purchase and installation. A three-part rate design makes significant progress toward addressing essentially all of the issues presented by the difficult transition underway to new DG technologies.

UNSE has nearly completed deployment of the necessary metering technology, and the Company recognizes that Staff's rate migration transition's success depends on a customer education plan to ensure as smooth a transition as possible. Staff recommends allowing as few customer exceptions to the migration as possible and only for specifically defined, vulnerable customer groups. Staff requests that parties respond in their rebuttal testimonies regarding the possible reasons for exemptions and the bases for identifying eligibility for exemptions.

Demand charges are not a new concept, but rather are in widespread use today for commercial and industrial customers. A demand charge is a proven successful rate design component which better reflects cost causation than rate designs which rely upon energy charges only to recover utility fixed costs. Metering and communications technology improvements, DG penetration, and recent regulatory issues have made its adoption for residential and small general service customers possible, appropriate, timely, and even necessary.

Q. How does a utility recover fixed costs under a two-part tariff versus a three-part tariff?

A. In a two-part tariff, a utility recovers all of its costs, fixed costs included, in the monthly minimum charge and the energy charge(s). Monthly minimum costs are the minimum additional costs to serve a customer connection and are generally defined narrowly as billing and metering related costs. The energy charge recovers all further variable costs, such as fuel for electric generation, and all remaining fixed costs. Hence, at the level of the individual customer, reduction of energy consumption reduces recovery of fixed costs for the utility from that customer. Whether or not that reduced recovery is a concern for the utility depends on what happens in that time frame with the energy consumption of all other customers. A reduction from one customer can be offset by increased consumption from other customers. However, when there is a reduction in energy consumption in total, especially as compared to the level approved for a utility based on its adjusted test year, an under recovery of fixed costs may occur. It is complicated because even in that situation the utility may be able to recover fixed costs by selling energy to other neighboring utilities or entities.

A three-part tariff, on the other hand, applies a demand charge to the maximum usage for a defined period (e.g., one-hour) for the applicable period (e.g., on-peak). It is not unusual for customers to reduce demand by less than they reduce energy consumption because they may not be able to reduce energy consumption for the entire period that the demand charge applies. By definition, a demand charge is designed to recover a utility's fixed costs even if the utility's infrastructure is used only for the minimum period of time (i.e., one-hour).

Q. What significant problems are associated with the continued use of the existing two-part residential rate design in this timeframe?

A. Rate design is premised upon the assumption that a customer's test year energy consumption serves as a reliable estimate of future use. This is an inherent weakness, especially in the present circumstances wherein more and more customers are adopting DG technology.

A customer who newly adopts DG is likely to consume fewer kWhs than in the test year. Such DG customers avoid paying a significant portion of the utility's fixed costs even though DG customers continue to use the grid. The same can be said of many other customers, such as seasonal customers, customers adopting energy efficiency measures and customers implementing lifestyle changes which reduce energy consumption, without reducing their use of the electricity grid. DG customers are receiving attention now because they are currently exacerbating the rate design's weakness. Whether or not such DG customer behavior is a significant problem for a utility such as UNSE at the aggregate level, depends on many factors including whether or not the utility, for example, can use its infrastructure for other customers to meet customer growth or to make sales to other utilities.

At the aggregate level, UNSE has been experiencing reduced sales as mining loads are reduced, energy efficiency is successful, and their service territory is slow to recover from the economic down-turn. While reduced fixed cost recoveries are re-allocated (i.e., shifted) in subsequent rate cases (or more quickly in the interim by lost fixed cost recovery ("LFCR") mechanisms), there is the potential for other customers to shoulder more of the fixed costs. In response, regulators have been asked to authorize capacity kW charges applicable only to DG customers and based on DG capacity installed on the grid rather than on the remaining intensity of DG customers' grid usage. Such grid charges run the risk of being set too low or too high and, therefore, recovering less than or more than the portion of infrastructure still utilized by DG customers. Quite simply, installed DG capacity kW is not equal to the remaining demand kW intensity of use (although there is a correlation).

Ultimately, this scenario leaves utilities such as UNSE in the position of having to maintain their grids at a time when they are facing additional sources of downward pressure on energy sales, including energy efficiency programs, the pending Clean Power Plan, and a post-recession no-growth or very slow-growth service territory. However, a three-part tariff recovers fixed costs for that portion of the grid that DG customers (and all other customers for that matter) utilize.

The above described consequences are largely unnecessary and avoidable with the timely adoption of a demand kW charge in three-part residential and small general service tariffs.

Q. Can these consequences be eliminated by implementing a 3-part rate design?

A. Yes. A well designed three-part tariff with a kW charge as Staff proposes in the testimony of Mr. Howard Solganick can largely eliminate this problem and its consequences. Utilities can recover their fixed costs for the amount of the grid their customers use and most DG customers will still be able to save on their monthly electric utility bills (though probably not as much as previously without taking further actions).

A demand kW charge, applicable during on-peak hours, will even better recover the fixed costs assigned to residential and small general service customers. It will better assist customers to avoid utility costs, and it will encourage the adoption of additional technologies. A proper three-part rate design can align many stakeholder interests rather than place them into unnecessary and repetitive conflict. It will be important not to create too high of a demand kW charge in the first instance and to move to full cost gradually over two or three rate cases. Also, Staff recommends that demand kW for residential and small general service customers be measured and billed for a period of time not shorter than one hour.

Q. But doesn't UNSE's proposal to require only new DG customers to incur a demand kW charge also largely solve the identified list of problems?

A. It would to some degree, but not to the extent of Staff's proposal. It would be unfair to new DG customers and it would perpetuate existing problems and create a new set of problems with potentially difficult and negative consequences. Staff is proposing a more complete solution. Staff does not agree with UNSE's proposal to treat new DG customers differently from existing DG customers in regard to the availability of tariff(s) offered by their utility. Staff believes the DG concern is an emerging concern for utilities and not yet of such a significant magnitude to warrant a one-off approach. For the most part, a utility's concern relates to future periods from forecasting continued DG penetration at increasing rates.

Furthermore, a demand kW charge applicable only to new DG customers would occur simultaneously with a customer's decision on whether or not to install DG, a major investment decision for customers. Even if customers receive history on their demand kW usage and receive a good explanation of a three-part tariff, customers would not likely have any actual previous experience with a three-part tariff. Customers, therefore, may not know to inquire about other lifestyle changes or other technology choices that are alternatives to or useful additions to DG. Mistakes could be very costly to consumers and are unnecessary. Staff concludes it is best if utility rates are designed to be neutral, agnostic, and unbiased towards the technology and lifestyle choices of customers. Rather, customers should pay for (only) the costs they impose on their utilities. Staff concludes that a three-part tariff can recover the costs of service incurred by the utility, even if a customer class is nonhomogeneous and exhibits a wide range of, for example, load factors. DG customers are most likely formerly high load factor customers that have become low load factor customers.

A one-off tariff regime for new DG threatens to unravel the long-lasting system of subsidies and premiums embedded in existing utility rates. These existing subsidies do not need to be fully threatened as a result of new technology. Once DG customers are singled out for special treatment, it sets a precedent for singling out other customer categories enjoying other subsidies. Residential class customers, seasonal customers, low load factor customers, low energy usage consumers, and rural customers are among those groups who typically receive significant subsidies from other customer groups under existing class cost assignments and two-part tariffs. On the other hand, commercial and industrial customers, year-round residential customers, high load factor customers, higher energy usage consumers, and urban customers, are among those groups of customers often paying subsidies under a two-part tariff. Subsidies for seasonal customers, low load factor customers, and low energy usage consumers would be reduced under a gradual transition to a three-part tariff. It is not necessary at this time to trigger a full re-evaluation and unwinding of the various other subsidies.

Staff believes that new meter technology, internet communications portals, and smart phone applications have made it feasible and much easier for residential customers to understand and accept a three-part tariff than ever before. Staff's proposal will be a big step forward in reflecting cost causation in rates over time without unfairly singling out sub-groups of customers and risking unraveling of all subsidies. If the Commission were to conclude that a migration to a three-part tariff should be voluntary, Staff recommends that it be voluntary for all DG customers as well.

Q. Would DG customers be able to avoid on-peak demand kW charges under a three-part tariff even while consuming less energy kWh?

A. Not unless they can reduce usage for the entire peak period. Under Staff's proposal to apply a kW charge during on-peak hours (e.g., summer weekdays between 2 p.m. to 8 p.m.), DG customers cannot avoid demand kW charges unless they reduce the intensity of their grid usage for the entire on-peak period. (Staff witness Mr. Howard Solganick addresses the time-of-use feature of Staff's proposal.)

Solar DG customers will, therefore, need to carefully consider their lifestyle decisions and additional related technology choices for those hours, for example, in the summer from when the sun starts to set and until 8 p.m. Home pre-cooling, postponing cooking and laundry, battery storage, energy efficiency, smart thermostats, and load controllers are among the additional possible choices residential customers might consider and implement in addition to or in lieu of DG. Under Staff's proposal, residential customers would largely already be familiar with life under a demand kW charge tariff before selecting DG and would be much better informed for making follow-on technology and lifestyle decisions, including DG.

Q. Will Staff's proposal create as many problems as it resolves?

A. No. Staff believes residential customers can be quickly educated and that a transition period as proposed by Mr. Howard Solganick is reasonable. Staff believes there will only be a temporary challenge for residential customers to understand, accept and adapt if the Company develops and implements a customer education program. Staff requests that UNSE define and develop the details for a rate migration transition process and share with the parties in its rebuttal testimony.

Q. Why not raise the monthly customer charge in lieu of a demand kW charge and keep a two-part tariff?

A. Such an increase would be unacceptably large. Staff strongly opposes addressing the described under recovery of utility fixed costs in this manner. Staff believes this would be highly unfair and unpopular to raise significantly the monthly customer charge, especially with residential customers. It would eliminate nearly all customer ability to control or reduce electric bills. It would be highly unfriendly to new technologies and a major step backwards. Staff recommends keeping the monthly customer charge narrowly focused on the cost of a meter, the costs of customer service and billing and the cost of the service line. Staff goes as far as it is willing to go in accepting UNSE's proposal to include distribution costs for a minimum sized system in its monthly minimum charge as discussed by Staff witness Mr. Howard Solganick.

Q. Is Staff requesting vulnerable groups to self-identify?

A. Yes. Staff does not presume that any group is so vulnerable as to be unable to understand and tolerate a demand kW charge. Customer vulnerability is quite different than mere opposition to an anticipated (initial) discomfort with a transition from a two-part to a three-part tariff. Nevertheless, Staff is interested in considering feedback from potentially vulnerable groups. Staff looks forward to input from other participants in this case regarding the reasons for vulnerability (e.g., high kW medical equipment), methods to identify such vulnerable customers, and appropriate alternative pricing. Staff prefers that methods to identify vulnerable customers be precise and not subject to manipulation. Staff prefers vulnerable groups be narrowly and specifically defined so as to not become too large.

Staff witness Mr. Howard Solganick expresses Staff's willingness for the record in this case to remain open for a period following a decision. This process might allow for possible adjustments to eligibility for status as a vulnerable customer.

For completeness, please note that Staff does not believe that *existing* DG customers comprise a vulnerable group. In other words, existing DG customers should participate in the migration to a three-part tariff under Staff's proposal. They are not to be "grandfathered" regarding their utility tariff for their electricity purchases.

Q. If Staff's proposal is adopted, will DG need to remain a component of the LFCR?

A. Only for a while. Staff's proposal is to only rely on the LFCR's DG component for the recovery of eligible costs from the end of the test year until new rates are effective in this case. Once new rates are effective, no new lost fixed costs would be considered in the LFCR's DG component. As residential and small general service customers successfully migrate to a three-part tariff, the need for DG to remain as a component of the LFCR is greatly reduced and eliminated following the full transition. The DG portion of the LFCR can, therefore, be eliminated in the Company's next rate case.

Q. What about subsequently imposing grid reset charges in the interim between rate cases?

A. A three-part tariff also makes this step unnecessary. At this time, Staff is opposed to imposing grid capacity kW reset charges on DG customers either between rate cases or as a result of a rate case. Staff concludes that it is the opposite of sound rate design principles to impose a charge on the amount of demand kW the customer is *removing* from the system; rather, it is wise to impose a kW charge for the amount of a utility's system the DG (or any) customer uses.

STAFF'S NET METERING AND VALUE AND COST OF DISTRIBUTED GENERATION RECOMMENDATIONS

Q. Why does Staff not support the Company's Renewable Credit Rate ("RCR") net metering rider at this time?

A. While Staff appreciates the Company's proposal, Staff has a number of concerns, including those expressed by Staff witness Mr. Howard Solganick, that it would like the Company to address. Staff notes that Commission Docket No. E-00000J-14-0023, which is intended to examine the value and cost of DG, may provide useful information to the parties in this rate case. Therefore, for the time being, Staff does not propose any changes to the existing net metering tariff or waivers of the net metering rules, but it may update its position in its surrebuttal testimony or later at the hearing in this case. If ultimately the Commission continues to rely upon net metering, the migration to a three-part tariff will not pose any issues as the energy kWh charges in a three-part tariff and on a time-of use basis would be used for net metering.

Q. Is Staff concerned about the frequency of updating the Company proposed RCR?

A. Yes. The frequency of updating as well as the dependence on only one agreement is concerning. The Company's proposal does not consider non-generation functional components either from an avoided cost perspective or from an apples to apples perspective of a resource substitution of utility-scale solar for rooftop solar. Staff also wants to consider further whether it prefers a net avoided cost plus adder method (as is the typical suggested approach in studies valuing solar) or whether it prefers a comparable resource cost method as the Company proposes or whether it depends on the circumstances of each utility.

Q. Does this conclude your direct rate design testimony?

A. Yes.

QUALIFICATIONS

THOMAS M. BRODERICK

Employment History

Director, Utilities Division, Arizona Corporation Commission, Phoenix, AZ (July 2015 - present)

Field Team Lead, Power Africa Project, Deloitte Consulting, Nairobi, Kenya (September 2013 - August 2014)

Director, Rates & Regulation, EPCOR and American Water, Phoenix, AZ (2004 - August 2013)

Director, External Affairs, PG&E National Energy Group, Phoenix, AZ (2001 - 2003)

Senior Energy Advisor, USAID, US Embassy, Kiev, Ukraine (1999 – 2000)

Consultant, PG&E Energy Services Corporation, Phoenix, AZ, (1997 – 1998)

Manager / Supervisor, Planning, Forecasts and Regulatory Affairs, APS, Phoenix, AZ (1984 – 1996)

Marketing Research Analyst, Miller Brewing Company, Milwaukee, WI (1982-1984)

Economist, Illinois Health Finance Authority, Chicago, IL (1981-1982)

Education

M.S., Economics, University of Wisconsin, Madison (1981)

B.S., Economics, Arizona State University, (1979)

EXHIBIT
S-17
~~ADMITTED~~

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
Commissioner
ANDY TOBIN
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. 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 UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

SURREBUTTAL

RATE DESIGN TESTIMONY

OF

THOMAS M. BRODERICK

DIRECTOR

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2016

TABLE OF CONTENTS

EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-15-0142

Mr. Broderick's surrebuttal testimony continues the discussion regarding Staff's proposed full transition from two-part to three-part rates for all of UNS Electric, Inc.'s ("UNSE") residential and small general service customers.

Staff proposes two additional mitigation measures for residential and small general service customers: A 15 percent bill credit to customers who adopted DG solar on or before June 1, 2015, and a temporary 15 percent incentive for new DG solar adopters during the six month period following full rate migration.

Based on UNSE's acceptance of a full migration to three-part rates in its rebuttal testimony, Staff now recommends continuing net metering without change in this case.

The primary reason Staff wants the record to remain open in this case is to be able to address any significant discrepancies between estimated and actual kW demands.

Staff further develops the concept of a ceiling on kW demand with aspirations for an eventual phase-out and post-case compliance filings.

As a component of its rate migration education program, UNSE should be required to provide customers with materials that list the major electrical appliances and end-uses over an estimated range of kW demands based on a review of appliance usage and saturation data relevant to UNSE's service territory.

Staff accepts UNSE's recommendation to transition all residential and small general service customers to three-part time-of use rates during one month, but Staff does not want UNSE to be required to do that.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Thomas M. Broderick. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Arizona Corporation Commission ("Commission") as Director of the Utilities Division ("Staff"). I submitted direct rate design related testimony on December 9, 2015, in this docket.

Q. What is the subject matter of your surrebuttal testimony?

A. The topics are listed in my Table of Contents. My surrebuttal testimony continues the discussion regarding Staff's proposed full transition from two-part to three-part rates for UNS Electric, Inc.'s ("UNSE") residential and small general service customers. UNSE has embraced Staff's long-term concept for such a rate migration. Staff encourages UNSE to continue to specify the transition details for its unique circumstances. Staff intends to be active throughout the entire implementation process to ensure a successful transition.

As UNSE has indicated, the transition from two-part to three-part rates is class revenue neutral for residential and small general service customers. Therefore, many of the Company's customers will save on their electric bills after the transition is completed without doing anything differently. For other customers, Staff (and UNSE for that matter) are working hard to listen, understand, and address specific identified and reasonable concerns.

Thus far, mitigation measures proposed or accepted by Staff and/or UNSE to assist residential and small general service customers include: 1) Gradualism in class allocations of increased costs to serve; 2) Gradualism in class allocations of demand costs which reduce the kW demand charge in this case; 3) A ceiling on kW demand incorporated into tariffs at a 15 percent load factor; 4) A thorough, widely available and thoughtful customer education program; 5) A carefully designed rate migration implementation process; 6) A case left open for 18 months; 7) A kW demand measurement period not shorter than one hour and measured only during on-peak periods; 8) Various useful post-case compliance requirements; and 9) Disclosure of intentions and general aspirations of how rate design may evolve in the future under three-part time-of-use rates.

Staff proposes two additional mitigation measures for residential and small general service in my surrebuttal testimony: A bill credit to customers who adopted DG solar on or before June 1, 2015, and a temporary 15 percent incentive for new DG solar adopters during the six month period following full rate migration.

STAFF'S PROPOSED MITIGATION MEASURE FOR EXISTING DG CUSTOMERS

Q. Please summarize Staff's rate design proposal, as set forth in Staff's direct testimony.

A. In its rate design testimony, Staff proposed a mandatory transition from two-part to three-part rates for all UNSE residential and small general service customers, unless a particular category of customers could somehow establish that it is "vulnerable" in some manner to the three-part rate. Staff's initial conclusion was that DG customers were unlikely to be vulnerable.

Q. Is Staff revising its position stated on December 9, 2015, regarding "grandfathering" of existing DG solar customers' tariffs?

A. No. Staff maintains that demand charges are a reasonable way to allocate costs for recovery. My earlier testimony stated "...all existing DG customers should participate in the migration to a three-part tariff under Staff's proposal like everyone else." (Broderick Direct, Page 10, Lines 6-7). Although Staff continues to support this statement, based on subsequent input from parties, further independent review, discussion, and reflection, Staff now augments its original position in order to mitigate a portion of the estimated impact of the transition from two-part to three-part rates for existing DG customers.

Q. What input has Staff received from other parties in this case about Staff's original proposal, particularly as to how it could affect existing DG customers?

A. Some parties believe that demand charges will unfairly impact existing DG customers. In particular, it has been suggested that "net-zero" customers will receive a significant bill increase as a result of the transition to three-part rates. A net-zero customer is one who is able to offset all kWh charges through the output of his solar panels. As a result, a net-zero customer pays the monthly customer charge, but avoids all kWh charges. As these customers transition to three-part rates, they would see a new demand charge (that cannot be offset by kWh production) in addition to the higher monthly customer charge. Because these customers are currently avoiding kWh charges, the impact of the transition to three-part rates will be more significant for them than for other customers.

Q. Do these comments raise valid concerns?

A. These comments raise concerns about gradualism. While I do not know the exact number of existing DG customers who would face significant impacts, UNSE stated in discovery that approximately 57 percent of existing DG solar customers are net-zero customers. In sum, according to UNSE, the majority of its existing residential DG customers are likely to be net-zero customers, and the balance of the Company's remaining DG customers are close to net-zero.

Q. Has Staff attempted to develop a quantitative approach for helping evaluate this issue?

A. Yes. In surrebuttal testimony filed contemporaneously herewith, Staff witness Yue Liu has evaluated the relevant financial, technical, and usage parameters associated with the adoption of DG by residential customers.

Q. Please discuss the context of the surrebuttal testimony of Staff witness Liu.

A. Staff is, as always, tasked with finding and recommending a balanced solution. For the most part, the utilities have been predicting severe consequences from the failure to immediately address technology-related cost shifts. Yet, technology vendors have been predicting that customers will no longer select solar if there is any change in the status quo for rate design and net metering. This large gap in positions, in Staff's opinion, has not yet been filled with evidence relating to customer response to changes in rate design.

As a result, Mr. Liu was tasked with reviewing discovery responses provided by several parties in order to develop financial, usage, and operational spreadsheet models that can be used to analyze the decision to purchase DG solar from the customer's perspective. In order to provide the complete investment picture, the customer's perspective includes not only savings on electric bills and compensation for electricity export, but also the cost of purchasing or leasing DG solar.

Mr. Liu was also tasked with evaluating, on behalf of Staff, the various inputs, assumptions, and calculations received from the parties and modifying those inputs as appropriate. Given that Staff has already proposed a long-term plan for reducing/eliminating cost shifts (i.e., three-part rates), the primary purpose of his effort is to assess the impact of various rate design proposals on the customer's pay-back period and internal rate of return. A longer pay-back and a lower rate of return discourage adoption of solar; a shorter pay-back and higher rate of return encourage it.

Q. What were the results of this analysis relating to migration of existing DG solar customers from a two-part to a three-part rate design?

A. His testimony indicates lower (but still positive) rates of return on DG solar after migration to UNSE's revised proposed three-part TOU Demand tariff. However, he estimates that average DG residential customers will experience an increase of $10.06 under three-part as compared to two-part or an additional 20.28 percent, excluding any increase in the monthly basic minimum charge. For large DG residential customers, the increase is $20.44 and 31.82 percent. These increases are in addition to the revenue requirement increase assigned to the residential class.

Q. In light of the higher monthly bills and lower rates of return on DG solar that are likely to result from a migration to a three-part tariff, should the Commission consider additional mitigation measures for existing DG solar customers?

A. Yes. Additional mitigation measures for these customers would be consistent with principles of gradualism. Because the effects of the transition to three-part rates are likely to be greater for existing DG customers than for other customers, some further mitigation is appropriate. Furthermore, Staff recognizes that many early adopters of solar took a risk in their decision to install solar systems. Over the years, solar system purchase prices have decreased substantially, but many of the early adopters paid substantial amounts to install their systems.

Q. What specific mitigation measures does Staff now recommend?

A. Staff recommends that the Commission require UNSE to offer a 15 percent bill credit to customers who adopted DG on or before June 1, 2015. The dollars needed to offset the bill credit should be collected through a surcharge that is assessed to all of UNSE's customers. Staff requests UNSE to calculate and propose the details for this new surcharge. UNSE's proposed rate design would need to migrate existing DG solar customers from two-part to three-part rates and also apply a 15 percent discount. Based on Staff's estimates, that result would be less costly to non-DG solar customers than the Company's original proposal to grandfather.

Q. What is the basis for a 15 percent bill credit?

A. As previously discussed, the bill impacts related to rate migration for existing DG customers will likely fall within a range of approximately 20 to 30 percent. A 15 percent bill credit represents mitigation of a significant portion of the estimated impact. By way of comparison, the UNSE CARES discount supported by Staff and UNSE is 18 percent with a $16/month cap. Staff believes that partial rather than full mitigation is the more appropriate goal.

Q. Why has Staff recommended June 1, 2015 as a cutoff date for eligibility for the bill credit?

A. Staff concludes that the cut-off date of June 1, 2015, or any other date through the date of a decision in this case, is reasonable and acceptable to Staff for determining customer eligibility for its proposed mitigation. It is much less likely that applicants processed after June 1, 2015 will be comparably financially harmed, as DG solar costs per kW have been declining.

Q. How long should this mitigation measure remain in place?

A. The need for continuing the 15 percent bill credit should be evaluated again in the Company's next rate case. Staff recognizes that some parties believe that various mitigation measures should be "grandfathered." For example, UNSE has suggested a twenty-year horizon, with an end date of May 31, 2035. Staff prefers instead to revisit these issues in UNSE's future rate cases.

Q. Why has Staff recommended a surcharge to recover the costs of the bill credit?

A. A surcharge provides simplicity and transparency.

Q. Are Staff's proposed mitigation measures independent of its rate design recommendations?

A. No. This augmented Staff position assumes (and is dependent upon) the Commission ultimately approving Staff's proposed migration to three-part tariffs. The rate design proposals recommended by the other parties to this case may not create any special need for mitigation, or may require different types of mitigation.

Q. Should future DG customers be eligible for mitigation-type discounts in future rate cases?

A. The need for continuing and expanding the bill credit will likely be evaluated again in the Company's next rate case. However, Staff wants to make it clear that it is likely to be opposed to extending special mitigation discounts to any *future* DG customers.[1] Future DG customers should be on notice that Staff is unlikely to support mitigation measures for the effects of future rate changes or other terms-of-service changes.

[1] A future customer is any application submitted on or after June 1, 2015, under Staff's proposal or by another eligibility cut-off date established by the Commission in its decision. A future customer should include previously eligible customers that install a replacement solar system after May 31, 2015.

Q. Does Staff have any other considerations regarding future UNSE rate cases?

A. Yes. To-date, Staff has evaluated the need for mitigation measures largely in reliance upon statements from the solar industry and upon the Staff analyses conducted by Mr. Liu. In UNSE's next rate case, the degree to which actual, existing DG customers provide public comment or otherwise participate in the case is likely to be relevant to whether Staff will continue to support continuing the bill credit for existing DG customers. Additionally, Staff may ask the solar industry to consider sharing a portion of the burden of continuing mitigation for existing DG customers.

STAFF'S RECOMMENDATION ON NET METERING AND VALUE OF SOLAR

Q. UNSE accepted Staff's proposal for a full migration to three-part rates for residential and small general service customers. Does Staff now have an associated recommendation on net metering as an appropriate reflection of the net value of DG solar?

A. Yes. In my December 9, 2015 direct testimony, I stated "for the time being, Staff does not propose any changes to existing net metering, but it may update its position in its surrebuttal testimony or later at the hearing in this case." (Broderick Direct, Page 11, Lines 10-12). Further, I made reference to the Commission's on-going generic Value and Cost of Solar docket (No. 14-0023). Some parties interpreted these statements as implying that Staff would not make a recommendation in this case regarding net metering and the net value of solar until a decision had been reached in *that* case. However, based on UNSE's acceptance of a full migration to three-part rates in its rebuttal testimony, Staff now recommends continuing net metering without change in this case.

Staff believes that UNSE either supported or hinted at its likely support for continuing net metering without change in its rebuttal testimony.[2] Staff understands that UNSE may be unwilling to continue net metering if specific parameters of a three-part rate design later become unacceptable. However, it would be helpful if UNSE would confirm Staff's understanding of its acceptance of continuing net metering unchanged (at least until its next rate case) in rejoinder or at hearing.

Q. How do the energy kWh rates proposed by UNSE in its rebuttal testimony for a three-part residential time-of-use rate compare to its earlier proposal to compensate exports at a 5.84 cents per kWh renewable energy credit?

A. Energy kWh rates are significant because they form the basis for compensation for exports under net metering. The rates proposed by UNSE in its rebuttal testimony are higher for all periods except Winter Off-Peak. UNSE proposed the following energy charges in its residential three-part time-of-use rate proposal:[3]

Energy Charge (kWh's), Applicable on all kWh's	1.6760 cents/kWh
Base Power Supply Charge, Summer On-Peak all kWh's	10.2251 cents/kWh
Base Power Supply Charge, Summer Off-Peak all kWh's	4.2830 cents/kWh
Base Power Supply Charge, Winter On-Peak all kWh's	8.2000 cents/kWh
Base Power Supply Charge, Winter Off-Peak all kWh's	3.8610 cents/kWh

The Summer On-Peak (1.6760 plus 10.2251 cents/kWh), Summer Off-Peak (1.6760+4.2830 cents/kWh) and Winter On-Peak (1.6760 plus 8.2000 cents/kWh) rates are each higher than 5.84 cents per kilowatt-hour. Only the Winter Off-Peak proposed rate (1.6760 plus 3.8610 cents/kWh) is lower than the original UNSE proposed renewable energy credit of 5.84 cents

[2] Tilghman Rebuttal, Page 3, Lines 17-18.
[3] Jones, Rebuttal Exhibit CAJ-R-4, page 4 of 7.

per kilowatt-hour. These proposed rates are, of course, subject to further revision as this case progresses.

Staff believes that compensation to DG solar customers will be higher per kWh under UNSE's revised proposal versus its original rate design proposal. It is noteworthy that the existing banking provision of net metering allows kWhs, which are often generated in winter, to carry over into summer at the respective On- and Off-Peak summer rates.

Again, Staff's recommendation for net metering assumes (and is dependent upon) acceptance of the proposed full migration from two-part to three-part rates. Staff is comfortable continuing net metering for UNSE with that assumption without concluding on-going Docket No. E-00000J-14-0023.

STAFF'S RECOMMENDATION ON LOST FIXED COST RECOVERY ("LFCR")

Q. Is Staff suggesting that UNSE should be required in this case to accept the elimination of the DG component of the LFCR by the conclusion of UNSE's next rate case?

A. No. UNSE witness Mr. Jones expressed a concern that Staff was making this a requirement in the instant docket.[4] To clarify, Staff has identified, as an appropriate aspirational goal, that the DG component of the LFCR would be eliminated in a subsequent UNSE rate case. This elimination would occur only upon a successful migration to three-part rates and a continuing evolution of rate designs, as appropriate, based on then existent facts. Both Staff and UNSE agree on the principle of gradualism in rate design, and both acknowledge that the proposed kW demand charge does not fully address UNSE's fixed cost recovery.

[4] Jones Rebuttal, Page 4, Lines 25-27.

To avoid any misunderstanding in post-case compliance, Staff recommends that UNSE submit a specific updated LFCR plan of administration ("POA") not later than the time of hearing. The updated POA would apply through the conclusion of UNSE's next rate case and include the proposed impact on the LFCR given UNSE's proposal regarding the percentage of functionalized (i.e., G, T, D) fixed costs recovered in the kW demand charge, the monthly minimum charge, and the energy charges.

As a result, Staff concludes that the parties do not need to fully address in this docket the issue of further recovery of fixed distribution and generation costs as rate designs become more cost-based in subsequent cases.

STAFF'S RECOMMENDATION TO HOLD OPEN THE RATE CASE TO ADDRESS POTENTIAL UNINTENDED CONSEQUENCES

Q. Why does Staff recommend that the Commission hold open the rate case?

A. Staff wants to be able to address any discrepancies between estimated and actual kW demands. As UNSE witness Mr. Jones indicates, UNSE is relying upon estimates of kW demand from its load research data.[5] Should its kW estimates used in designing rates ultimately prove too low, then the kW charge should be decreased. Should kW estimates ultimately prove too high, then the kW charge should be increased. The concern is not over a minor discrepancy; however, a significant difference could create serious unintended consequences that should be timely addressed. The purpose of holding the case open for 18 months is to allow for the passage of enough time to fairly and accurately determine if significant discrepancies exist.

Although not the primary focus, other unanticipated consequences, if any, could also be addressed.

[5] Jones Rebuttal, Page 6, Lines 19-21.

STAFF'S PROPOSED KW DEMAND CEILING

Q. Does a ceiling on kW demand protect customers from unexpectedly high bills?

A. Yes. From a review of the testimony in this case, Staff concluded that no new vulnerable *groups* are created per se as a result of a full migration to three-part rates; instead, there is a broad based concern that individual customers will experience unexpectedly high kW demands, at least for a period until customers become accustomed to three-part rates. Some parties believe that it will be challenging not only to educate customers about the reasons for unexpectedly high kW, but also to teach them how to avoid such surprises. Some parties highlighted various lifestyle situations and events for which it may be difficult to manage kW demand.

As a mitigation measure, Staff and UNSE have discussed the concept of placing a ceiling on kW demand for each customer through the use of a minimum load factor. UNSE later responded with a detailed specific proposal for a minimum load factor of 15 percent for each customer. This proposal was fully developed by UNSE witness Mr. Jones.[6]

Simply put, with this ceiling on kW demand, no customer can experience a significant kW billing surprise. All residential and small general service customers, including DG solar customers, would be eligible for the ceiling on kW demand. For DG solar customers, their calculation would be based on their "site" energy consumption.[7] For DG solar customers, site load equals kWh self-consumption plus kWh purchases from UNSE, which therefore excludes kWh produced and exported to the grid.

Staff recommends that UNSE include the specifics of the proposed ceiling on kW demand in its revised proposed tariffs in rejoinder or at hearing.

[6] Jones Rebuttal, Page 13, Line 8 to Page 15, Line 23.
[7] Jones Rebuttal, Page 14, Line 5.

Q. Should the kW ceiling be phased-out in time?

A. Yes. UNSE has expressed a preference for phasing out a ceiling on kW demand in the decision in its next rate case.[8] Staff agrees with UNSE that a ceiling on kW demand is a transitional mechanism that should ultimately be phased-out. However, Staff is presently unable to support its elimination in UNSE's next rate case. Staff would expect, at a minimum, that the ceiling on kW demand would be increased, perhaps based on a 10 percent or 5 percent load factor. The kW ceiling would increase as the load factor decreases. To facilitate this decision in the next UNSE rate case, Staff recommends that the Commission require UNSE to report at least annually the following compliance items, beginning one year after the effective date of the decision in this case:

1) The annual and monthly total number of customer bills exceeding the kW ceiling on demand by residential and small general service customer classes;
2) The annual and monthly total amount of unbilled kW demand and associated revenue savings by residential and small general service customer classes; and
3) The same statistics as 1) and 2), provided separately for CARES customers and DG solar customers.

STAFF'S RECOMMENDATION ON MITIGATION FOR FUTURE DG SOLAR

Q. Is Staff concerned about the potential for a temporary reduction in DG solar installations in the period immediately following customer migration to a three-part rate?

A. Yes. In the months after the transition from two-part to three-part rates, residential and small general service customers may not have adequate (i.e., 12 months) kW billing history upon which to base a sound DG solar decision. Additionally, there may be a brief period of customer

[8] Jones Rebuttal, Page 15, Lines 21-23.

confusion or hesitation in the aftermath of rate migration. For that reason, Staff recommends that UNSE establish a 15 percent cost per kW incentive for DG solar installations, effective for the first six months following the completion of the full transition from two-part to three-part rates in early 2017. Please refer to Mr. Liu's testimony for the basis of a 15 percent incentive.

Staff requests that UNSE identify at hearing a method to fund this incentive using REST funds either from a 2015 or 2016 carryover or in the 2017 program.

STAFF'S RECOMMENDATION ON CUSTOMER EDUCATION

Q. Is it important that customers have information on the estimated range of kW demand for individual appliances and other electrical end uses prior to the transition to three-part rates?

A. Yes. UNSE should be required to provide customers with materials that list the major electrical appliances and end-uses over an estimated range of kW demands based on a review of appliance usage and saturation data relevant to UNSE's service territory. It would also be helpful for UNSE to differentiate significant kW demands for select end-uses by on and off-peak time-of-use, if available. Air conditioning kW demand comes to mind as its use is typically more intensive on-peak than off-peak, but there may be other end-uses that vary with intensity by time-of-use.

Armed with this information, a customer can scan the list, become familiar with common electrical end-uses, and get an early indication of what causes kW demand usage and how to control it. As time passes and electric bills based on three-part rates are being experienced, customers can continue to refer to this list and begin to further refine kW demand experience.

Given some of the general concerns expressed by some parties, Staff wants customers to know how to successfully control kW demand in order to impact their bills. Staff wants customers to understand that significant kW demand appliances include such end-uses as air conditioners and electric clothes dryers. Likewise, Staff wants customers to understand that charging cell phones and using LED large screen TVs are low kW demands and are either not a concern or a relatively minor concern. Staff wants customers to be able to avoid needlessly trimming their lifestyles through limiting their low kW demand end-uses, which are unlikely to significantly impact bills.

Staff recommends that UNSE estimate a kW demand range for each identified end-use over a range of efficiency in its territory from less efficient models to new and highly efficient models.

Such materials should remind customers to confirm which appliances, if any, are supplied by natural gas and are thus nearly irrelevant to electrical kW demand, except for internal lighting or incidental electrical use.

Materials should also attempt to provide information on whole house kW demand ranges, perhaps based on home vintage as some older properties have less insulation. By contrast, new construction will likely already have a high energy efficiency designation.

Staff recommends that these materials be provided in various forms and/or media (e.g., internet) and at regular, appropriate time intervals to customers.

Staff recommends that UNSE provide, as a compliance item in the Commission's decision in this case, the above discussed materials and process descriptions 60 days prior to commencing the transition to three-part rates.

Staff also recommends that UNSE review its existing Energy Efficiency ("EE") programs and related educational materials, and revise them as appropriate at its earliest opportunity to support customer understanding of kW demand. Demand reducing programs should be considered in its next annual submittal.

STAFF'S RECOMMENDATION ON RATE MIGRATION TIMING

Q. Does Staff accept UNSE's recommendation to transition all residential and small general service customers to three-part time-of use rates during one month, billing cycle by billing cycle?

A. Yes, subject to UNSE's fulfilling the various obligations and responsibilities that Staff and other parties are discussing and that are ultimately incorporated by this Commission in its decision in this case.

UNSE should not be required to complete the transition in one billing month; rather, it should be permitted to do so. UNSE should be required to complete the transition within the 18 month period during which the case will remain open.

Q. Does this conclude your Surrebuttal testimony?

A. Yes.

EXHIBIT

S-18

admitted

Exhibit HS-6

LINE		TOTAL (A)	RESIDENTIAL SERVICE (B)	SMALL GENERAL (C)	MEDIUM/LARGE GENERAL (E)	LARGE POWER (F)	LIGHTING (H)
1	**75% of RES SGS to UROR = 1.00**						
2	Incremental Revenue	$15,100,000	$14,487,750	$1,774,875	-$1,013,318	-$139,176	-$10,247
3	Rate of Return on Rate Base	6.23%	3.32%	4.07%	12.67%	21.96%	2.60%
4	UROR	1.00	0.53	0.65	2.03	3.53	0.42
5	% Incr compared to Revenue From Present Sales	10.26%	19.67%	14.91%	-1.89%	-1.89%	-1.89%
6	% of the Total Increase	100.0%	95.9%	11.8%	-6.7%	-0.9%	-0.1%
7							
8							
9	**67.7% of RES SGS to UROR = 1.00**						
10	Incremental Revenue	$15,100,000	$12,884,439	$1,578,456	$555,795	$76,336	$5,620
11	Rate of Return on Rate Base	6.23%	2.36%	3.35%	14.88%	25.72%	3.70%
12	UROR	1.00	0.38	0.54	2.39	4.13	0.59
13	% Incr compared to Revenue From Present Sales	10.26%	17.49%	13.26%	1.04%	1.04%	1.03%
14	% of the Total Increase	100.0%	85.3%	10.5%	3.7%	0.5%	0.0%
15							
16							
17	**60% of RES SGS to UROR = 1.00**						
18	Incremental Revenue	$15,100,000	$11,590,200	$1,419,900	$1,821,341	$250,155	$18,417
19	Rate of Return on Rate Base	6.23%	1.58%	2.77%	16.66%	28.75%	4.60%
20	UROR	1.00	0.25	0.45	2.68	4.62	0.74
21	% Incr compared to Revenue From Present Sales	10.26%	15.74%	11.93%	3.39%	3.39%	3.39%
22	% of the Total Increase	100.0%	76.8%	9.4%	12.1%	1.7%	0.1%
23							
24							
25	**50% of RES SGS to UROR = 1.00**						
26	Incremental Revenue	$15,100,000	$9,658,500	$1,183,250	$3,710,667	$509,647	$37,522
27	Rate of Return on Rate Base	6.23%	0.42%	1.91%	19.33%	33.27%	5.93%
28	UROR	1.00	0.07	0.31	3.10	5.34	0.95
29	% Incr compared to Revenue From Present Sales	10.26%	13.11%	9.94%	6.91%	6.91%	6.91%
30	% of the Total Increase	100.0%	64.0%	7.8%	24.6%	3.4%	0.2%
31							
32							
33	**All UROR equals 1.00**						
34	Incremental Revenue	$15,100,000	$19,317,000	$2,366,500	-$5,583,200	-$1,042,000	$41,700
35	Rate of Return on Rate Base	6.23%	6.23%	6.22%	6.23%	6.23%	6.22%
36	UROR	1.00	1.00	1.00	1.00	1.00	1.00
37	% Incr compared to Revenue From Present Sales	10.26%	26.23%	19.88%	-10.40%	-14.13%	7.68%
38	% of the Total Increase	100.0%	127.9%	15.7%	-37.0%	-6.9%	0.3%
39							
40							
41	**Equal Percentage**						
42	Incremental Revenue	$15,100,000	$7,556,638	$1,221,442	$5,509,497	$756,711	$55,712
43	Rate of Return on Rate Base	6.23%	-0.84%	2.05%	21.86%	37.57%	7.20%
44	UROR	1.00	-0.13	0.33	3.51	6.04	1.16
45	% Incr compared to Revenue From Present Sales	10.26%	10.26%	10.26%	10.26%	10.26%	10.26%
46	% of the Total Increase	100.0%	50.0%	8.1%	36.5%	5.0%	0.4%
47							
48							
49	**UNS allocation from rejoinder - APPROXIMATE**						
50	Incremental Revenue	$15,100,000	$14,136,082	$1,528,313	-$549,020	-$68,000	$52,625
51	Rate of Return on Rate Base	6.23%	3.11%	3.17%	13.32%	23.20%	6.99%
52	UROR	1.00	0.50	0.51	2.14	3.73	1.12
53	% Incr compared to Revenue From Present Sales	10.26%	19.19%	12.84%	-1.02%	-0.92%	9.69%
54	% of the Total Increase	100.0%	93.6%	10.1%	-3.6%	-0.5%	0.3%

EXHIBIT
S-19
admitted

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending December 31, 2014

RESIDENTIAL SERVICE

BILL IMPACTS CURRENT RATES

	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill
		0-400	401-1,000	1,000+	$10.00	$0.019300	$0.034350	$0.038499	$0.001140	$0.064510	-$0.002139	
Xsmall	111	111	0	0	$10.00	$2.14	$0.00	$0.00	$0.13	$7.16	-$0.24	$19.19
Small	330	330	0	0	$10.00	$6.37	$0.00	$0.00	$0.38	$21.29	-$0.71	$37.33
Medium	664	400	264	0	$10.00	$7.72	$9.07	$0.00	$0.76	$42.83	-$1.42	$68.96
Large	1,144	400	600	144	$10.00	$7.72	$20.61	$5.54	$1.30	$73.80	-$2.45	$116.53
Xlarge	2,162	400	600	1,162	$10.00	$7.72	$20.61	$44.74	$2.46	$139.47	-$4.63	$220.37
Mean	830	400	430	0	$10.00	$7.72	$14.75	$0.00	$0.95	$53.51	-$1.77	$85.16
Sum	983	400	583	0	$10.00	$7.72	$20.04	$0.00	$1.12	$63.43	-$2.10	$100.20
Win	669	400	269	0	$10.00	$7.72	$9.25	$0.00	$0.76	$43.18	-$1.43	$69.48
Annual												$1,018.12

BILL IMPACTS - STAFF PROPOSED RATES

	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
		0-400	401-1,000	1,000+	$15.00	$0.024666	$0.034666	$0.052666	$0.000000	$0.055090	0.000%			
Xsmall	111	111	0	0	$15.00	$2.74	$0.00	$0.00	$0.00	$6.12	$0.00	$23.86	$4.66	24.3%
Small	330	330	0	0	$15.00	$8.14	$0.00	$0.00	$0.00	$18.18	$0.00	$41.32	$3.99	10.7%
Medium	664	400	264	0	$15.00	$9.87	$9.15	$0.00	$0.00	$36.58	$0.00	$70.60	$1.64	2.4%
Large	1,144	400	600	144	$15.00	$9.87	$20.80	$7.58	$0.00	$63.02	$0.00	$116.27	($0.26)	-0.2%
Xlarge	2,162	400	600	1,162	$15.00	$9.87	$20.80	$61.20	$0.00	$119.11	$0.00	$225.97	$5.60	2.5%
Mean	830	400	430	0	$15.00	$9.87	$14.89	$0.00	$0.00	$45.70	$0.00	$85.46	$0.30	0.3%
Sum	983	400	583	0	$15.00	$9.87	$20.22	$0.00	$0.00	$54.17	$0.00	$99.26	($0.95)	-0.9%
Win	669	400	269	0	$15.00	$9.87	$9.34	$0.00	$0.00	$36.88	$0.00	$71.09	$1.60	2.3%
Annual												$1,022.06	$3.95	0.4%

BILL IMPACTS - UNS PROPOSED RATES

	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
		0-400	401-1,000	1,000+	$15.00	$0.030100	$0.040100	$0.058100	$0.000000	$0.055090	0.000%			
		400	600	1000										
Xsmall	111	111	0	0	$15.00	$3.34	$0.00	$0.00	$0.00	$6.12	$0.00	$24.46	$5.27	27.4%
Small	330	330	0	0	$15.00	$9.93	$0.00	$0.00	$0.00	$18.18	$0.00	$43.11	$5.78	15.5%
Medium	664	400	264	0	$15.00	$12.04	$10.59	$0.00	$0.00	$36.58	$0.00	$74.21	$5.25	7.6%
Large	1,144	400	600	144	$15.00	$12.04	$24.06	$8.37	$0.00	$63.02	$0.00	$122.49	$5.96	5.1%
Xlarge	2,162	400	600	1,162	$15.00	$12.04	$24.06	$67.51	$0.00	$119.11	$0.00	$237.72	$17.35	7.9%
Mean	830	400	430	0	$15.00	$12.04	$17.22	$0.00	$0.00	$45.70	$0.00	$89.96	$4.80	5.6%
Sum	983	400	583	0	$15.00	$12.04	$23.39	$0.00	$0.00	$54.17	$0.00	$104.60	$4.40	4.4%
Win	669	400	269	0	$15.00	$12.04	$10.80	$0.00	$0.00	$36.88	$0.00	$74.72	$5.24	7.5%
Annual												$1,075.95	$57.83	5.7%

WINTER

RESIDENTIAL SERVICE DEMAND

BILL IMPACTS - STAFF PROPOSED TRANSITION RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill
				0-400	401-1,000	1,000+		0-400 kWh	401-1,000 kWh	1,000+ kWh				
							$15.00	$0.024666	$0.034666	$0.052666	$0.000000	$0.055090	$0.000000	
Xsm	23%	0.6	100	100	0	0	$15.00	$2.47	$0.00	$0.00	$0.00	$5.51	$0.00	$22.98
Small	27%	1.5	294	294	0	0	$15.00	$7.25	$0.00	$0.00	$0.00	$16.20	$0.00	$38.45
Medium	30%	2.6	560	400	160	0	$15.00	$9.87	$5.55	$0.00	$0.00	$30.85	$0.00	$61.26
Large	32%	3.9	914	400	514	0	$15.00	$9.87	$17.82	$0.00	$0.00	$50.35	$0.00	$93.03
XLg	35%	6.5	1,653	400	600	653	$15.00	$9.87	$20.80	$34.39	$0.00	$91.06	$0.00	$171.12
AnnAvg	32%	3.6	830	400	430	0	$15.00	$9.87	$14.89	$0.00	$0.00	$45.70	$0.00	$85.46
WinAvg	31%	3.0	669	400	269	0	$15.00	$9.87	$9.34	$0.00	$0.00	$36.88	$0.00	$71.09

BILL IMPACTS - STAFF PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
				On-Peak	Off-Peak		All kW	All kWh							
						$15.00	$5.00	$0.00991	$0.000000						
Winter				0.26	0.74					$0.086300	$0.038610	0.000%			
Summer										$0.105800	$0.042830				
Xsm	23%	0.6	100	26	74	$15.00	$2.95	$0.99	$0.00	$2.24	$2.86	$0.00	$24.04	$1.06	4.63%
Small	27%	1.5	294	76	218	$15.00	$7.45	$2.91	$0.00	$6.56	$8.42	$0.00	$40.34	$1.89	4.91%
Medium	30%	2.6	560	145	415	$15.00	$12.85	$5.55	$0.00	$12.51	$16.02	$0.00	$61.93	$0.67	1.09%
Large	32%	3.9	914	237	677	$15.00	$19.50	$9.05	$0.00	$20.45	$26.14	$0.00	$90.14	-$2.89	-3.11%
XLg	35%	6.5	1,653	429	1,224	$15.00	$32.25	$16.37	$0.00	$37.02	$47.26	$0.00	$147.90	-$23.22	-13.57%
AnnAvg	32%	3.6	830	215	614	$15.00	$17.90	$8.22	$0.00	$18.55	$23.71	$0.00	$83.38	-$2.08	-2.43%
WinAvg	31%	3.0	669	174	496	$15.00	$14.95	$6.63	$0.00	$15.02	$19.15	$0.00	$70.75	-$0.34	-0.47%

BILL IMPACTS - UNS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
				On-Peak	Off-Peak		All kW	All kWh							
						$15.00	$5.00	$0.01534	$0.000000						
Winter				0.26	0.74					$0.086300	$0.038610	0.000%			
Summer										$0.105800	$0.042830				
Xsm	23%	0.6	100	26	74	$15.00	$2.95	$1.53	$0.00	$2.24	$2.86	$0.00	$24.58	$1.06	4.51%
Small	27%	1.5	294	76	218	$15.00	$7.45	$4.51	$0.00	$6.56	$8.42	$0.00	$41.94	$1.89	4.72%
Medium	30%	2.6	560	145	415	$15.00	$12.85	$8.59	$0.00	$12.51	$16.02	$0.00	$64.97	$0.66	1.03%
Large	32%	3.9	914	237	677	$15.00	$19.50	$14.02	$0.00	$20.45	$26.14	$0.00	$95.11	-$2.89	-2.95%
XLg	35%	6.5	1,653	429	1,224	$15.00	$32.25	$25.36	$0.00	$37.02	$47.26	$0.00	$156.89	-$23.21	-12.89%
AnnAvg	32%	3.6	830	215	614	$15.00	$17.90	$12.73	$0.00	$18.55	$23.71	$0.00	$87.89	-$2.07	-2.31%
WinAvg	31%	3.0	669	174	496	$15.00	$14.95	$10.27	$0.00	$15.02	$19.15	$0.00	$74.39	-$0.33	-0.45%

Notes: 1. This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

3. $5.00 Demand rate used for ease of comparison

RESIDENTIAL SERVICE DEMAND

SUMMER

BILL IMPACTS - STAFF PROPOSED TRANSITION RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill
				0-400	401-1,000	1,000+		0-400 kWh	401-1,000 kWh	1,000+ kWh				
							$15.00	$0.024666	$0.034666	$0.052666	$0.000000	$0.055090	$0.000000	
Xsm	24%	0.7	117	117	0	0	$15.00	$2.89	$0.00	$0.00	$0.00	$6.45	$0.00	$24.34
Small	28%	1.9	386	386	0	0	$15.00	$9.52	$0.00	$0.00	$0.00	$21.26	$0.00	$45.78
Medium	32%	3.5	813	400	413	0	$15.00	$9.87	$14.32	$0.00	$0.00	$44.79	$0.00	$83.97
Large	34%	5.6	1,395	400	600	395	$15.00	$9.87	$20.80	$20.80	$0.00	$76.85	$0.00	$143.32
XLg	37%	9.1	2,471	400	600	1,471	$15.00	$9.87	$20.80	$77.47	$0.00	$136.13	$0.00	$259.27
AnnAvg	32%	3.6	830	400	430	0	$15.00	$9.87	$14.89	$0.00	$0.00	$45.70	$0.00	$85.46
SumAvg	33%	4.1	983	400	583	0	$15.00	$9.87	$20.22	$0.00	$0.00	$54.17	$0.00	$99.26
														$1,022.06

BILL IMPACTS - STAFF PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
				On-Peak	Off-Peak		All kW	All kWh							
						$15.00	$5.00	$0.00991	$0.000000						
Winter										$0.086300	$0.038610				
Summer				0.24	0.76					$0.105800	$0.042830	0.000%			
Xsm	24%	0.7	117	28	89	$15.00	$3.40	$1.16	$0.00	$2.96	$3.81	$0.00	$26.33	$1.99	8.19%
Small	28%	1.9	386	93	293	$15.00	$9.35	$3.82	$0.00	$9.84	$12.55	$0.00	$50.56	$4.78	10.44%
Medium	32%	3.5	813	196	617	$15.00	$17.60	$8.05	$0.00	$20.74	$26.43	$0.00	$87.82	$3.85	4.58%
Large	34%	5.6	1,395	336	1,059	$15.00	$27.95	$13.82	$0.00	$35.55	$45.36	$0.00	$137.68	-$5.64	-3.93%
XLg	37%	9.1	2,471	595	1,876	$15.00	$45.35	$24.48	$0.00	$62.95	$80.35	$0.00	$228.13	-$31.14	-12.01%
AnnAvg	32%	3.6	830	200	630	$15.00	$17.90	$8.22	$0.00	$21.16	$26.98	$0.00	$89.26	$3.80	4.45%
SumAvg	33%	4.1	983	237	747	$15.00	$20.70	$9.74	$0.00	$25.07	$31.99	$0.00	$102.50	$3.24	3.27%

BILL IMPACTS - UNS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
				On-Peak	Off-Peak		All kW	All kWh							
						$15.00	$5.00	$0.01534	$0.000000						
Winter										$0.086300	$0.038610				
Summer				0.24	0.76					$0.105800	$0.042830	0.000%			
Xsm	24%	0.7	117	28	89	$15.00	$3.40	$1.79	$0.00	$2.96	$3.81	$0.00	$26.96	$1.99	7.96%
Small	28%	1.9	386	93	293	$15.00	$9.35	$5.92	$0.00	$9.84	$12.55	$0.00	$52.66	$4.78	9.99%
Medium	32%	3.5	813	196	617	$15.00	$17.60	$12.47	$0.00	$20.74	$26.43	$0.00	$92.24	$3.85	4.35%
Large	34%	5.6	1,395	336	1,059	$15.00	$27.95	$21.40	$0.00	$35.55	$45.36	$0.00	$145.26	-$5.64	-3.74%
XLg	37%	9.1	2,471	595	1,876	$15.00	$45.35	$37.91	$0.00	$62.95	$80.35	$0.00	$241.56	-$31.14	-11.42%
AnnAvg	32%	3.6	830	200	630	$15.00	$17.90	$12.73	$0.00	$21.16	$26.98	$0.00	$93.77	$3.81	4.23%
SumAvg	33%	4.1	983	237	747	$15.00	$20.70	$15.08	$0.00	$25.07	$31.99	$0.00	$107.84	$3.24	3.10%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

3. $5.00 Demand rate used for ease of comparison

RESIDENTIAL SERVICE DEMAND

WINTER

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill
				0-400	401-1,000	1,000+		0-400 kWh	401-1,000 kWh	1,000+ kWh				
							$10.00	$0.019300	$0.034350	$0.038499	$0.001140	$0.064510	-$0.002139	
Xsm	23%	0.6	100	100	0	0	$10.00	$1.93	$0.00	$0.00	$0.11	$6.45	-$0.21	$18.28
Small	27%	1.5	294	294	0	0	$10.00	$5.67	$0.00	$0.00	$0.34	$18.97	-$0.63	$34.36
Medium	30%	2.6	560	400	160	0	$10.00	$7.72	$5.50	$0.00	$0.64	$36.13	-$1.20	$58.79
Large	32%	3.9	914	400	514	0	$10.00	$7.72	$17.66	$0.00	$1.04	$58.96	-$1.96	$93.42
XLg	35%	6.5	1,653	400	600	653	$10.00	$7.72	$20.61	$25.14	$1.88	$106.64	-$3.54	$168.45
AnnAvg	32%	3.6	830	400	430	0	$10.00	$7.72	$14.75	$0.00	$0.95	$53.51	-$1.77	$85.16
WinAvg	31%	3.0	669	400	269	0	$10.00	$7.72	$9.25	$0.00	$0.76	$43.18	-$1.43	$69.48

BILL IMPACTS - STAFF PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
				On-Peak	Off-Peak		All kW	All kWh							
						15.00	$5.00	$0.00991	$0.000000						
Winter				0.26	0.74					$0.086300	$0.038610	0.000%			
Summer										$0.105800	$0.042830				
Xsm	23%	0.6	100	26	74	$15.00	$2.95	$0.99	$0.00	$2.24	$2.86	$0.00	$24.04	$5.76	31.54%
Small	27%	1.5	294	76	218	$15.00	$7.45	$2.91	$0.00	$6.56	$8.42	$0.00	$40.34	$5.98	17.42%
Medium	30%	2.6	560	145	415	$15.00	$12.85	$5.55	$0.00	$12.51	$16.02	$0.00	$61.93	$3.14	5.34%
Large	32%	3.9	914	237	677	$15.00	$19.50	$9.05	$0.00	$20.45	$26.14	$0.00	$90.14	-$3.28	-3.51%
XLg	35%	6.5	1,653	429	1,224	$15.00	$32.25	$16.37	$0.00	$37.02	$47.26	$0.00	$147.90	-$20.55	-12.20%
AnnAvg	32%	3.6	830	215	614	$15.00	$17.90	$8.22	$0.00	$18.55	$23.71	$0.00	$83.38	-$1.78	-2.09%
WinAvg	31%	3.0	669	174	496	$15.00	$14.95	$6.63	$0.00	$15.02	$19.15	$0.00	$70.75	$1.27	1.82%

BILL IMPACTS - UNS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
				On-Peak	Off-Peak		All kW	All kWh							
						15.00	$5.00	$0.01534	$0.000000						
Winter				0.26	0.74					$0.086300	$0.038610	0.000%			
Summer										$0.105800	$0.042830				
Xsm	23%	0.6	100	26	74	$15.00	$2.95	$1.53	$0.00	$2.24	$2.86	$0.00	$24.58	$6.30	34.49%
Small	27%	1.5	294	76	218	$15.00	$7.45	$4.51	$0.00	$6.56	$8.42	$0.00	$41.94	$7.58	22.08%
Medium	30%	2.6	560	145	415	$15.00	$12.85	$8.59	$0.00	$12.51	$16.02	$0.00	$64.97	$6.18	10.52%
Large	32%	3.9	914	237	677	$15.00	$19.50	$14.02	$0.00	$20.45	$26.14	$0.00	$95.11	$1.69	1.81%
XLg	35%	6.5	1,653	429	1,224	$15.00	$32.25	$25.36	$0.00	$37.02	$47.26	$0.00	$156.89	-$11.56	-6.86%
AnnAvg	32%	3.6	830	215	614	$15.00	$17.90	$12.73	$0.00	$18.55	$23.71	$0.00	$87.89	$2.73	3.21%
WinAvg	31%	3.0	669	174	496	$15.00	$14.95	$10.27	$0.00	$15.02	$19.15	$0.00	$74.39	$4.91	7.06%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.
2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.
3. $5.00 Demand rate used for ease of comparison

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE DEMAND

SUMMER

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh) 0-400	Delivery (kWh) 401-1,000	Delivery (kWh) 1,000+	Basic Service Charge	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill
							$10.00	$0.019300	$0.034350	$0.038499	$0.001140	$0.064510	-$0.002139	
Xsm	24%	0.7	117	117	0	0	$10.00	$2.26	$0.00	$0.00	$0.13	$7.55	-$0.25	$19.69
Small	28%	1.9	386	386	0	0	$10.00	$7.45	$0.00	$0.00	$0.44	$24.90	-$0.83	$41.96
Medium	32%	3.5	813	400	413	0	$10.00	$7.72	$14.19	$0.00	$0.93	$52.45	-$1.74	$83.55
Large	34%	5.6	1,395	400	600	395	$10.00	$7.72	$20.61	$15.21	$1.59	$89.99	-$2.98	$142.13
XLg	37%	9.1	2,471	400	600	1,471	$10.00	$7.72	$20.61	$56.63	$2.82	$159.40	-$5.29	$251.90
AnnAvg	32%	3.6	830	400	430	0	$10.00	$7.72	$14.75	$0.00	$0.95	$53.51	-$1.77	$85.16
SumAvg	33%	4.1	983	400	583	0	$10.00	$7.72	$20.04	$0.00	$1.12	$63.43	-$2.10	$100.20

BILL IMPACTS - STAFF PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh) On-Peak	Delivery (kWh) Off-Peak	Basic Service Charge	Delivery All kW	Delivery All kWh	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
						$15.00	$5.00	$0.00991	$0.000000						
Winter										$0.086300	$0.038610				
Summer				0.24	0.76					$0.105800	$0.042830	0.000%			
Xsm	24%	0.7	117	28	89	$15.00	$3.40	$1.16	$0.00	$2.96	$3.81	$0.00	$26.33	$6.64	33.74%
Small	28%	1.9	386	93	293	$15.00	$9.35	$3.82	$0.00	$9.84	$12.55	$0.00	$50.56	$8.60	20.48%
Medium	32%	3.5	813	196	617	$15.00	$17.60	$8.05	$0.00	$20.74	$26.43	$0.00	$87.82	$4.27	5.11%
Large	34%	5.6	1,395	336	1,059	$15.00	$27.95	$13.82	$0.00	$35.55	$45.36	$0.00	$137.68	-$4.45	-3.13%
XLg	37%	9.1	2,471	595	1,876	$15.00	$45.35	$24.48	$0.00	$62.95	$80.35	$0.00	$228.13	-$23.77	-9.43%
AnnAvg	32%	3.6	830	200	630	$15.00	$17.90	$8.22	$0.00	$21.16	$26.98	$0.00	$89.26	$4.10	4.81%
SumAvg	33%	4.1	983	237	747	$15.00	$20.70	$9.74	$0.00	$25.07	$31.99	$0.00	$102.50	$2.30	2.29%

BILL IMPACTS - UNS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh) On-Peak	Delivery (kWh) Off-Peak	Basic Service Charge	Delivery All kW	Delivery All kWh	TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
						$15.00	$5.00	$0.01534	$0.000000						
Winter										$0.086300	$0.038610				
Summer				0.24	0.76					$0.105800	$0.042830	0.000%			
Xsm	24%	0.7	117	28	89	$15.00	$3.40	$1.79	$0.00	$2.96	$3.81	$0.00	$26.96	$7.27	36.94%
Small	28%	1.9	386	93	293	$15.00	$9.35	$5.92	$0.00	$9.84	$12.55	$0.00	$52.66	$10.70	25.49%
Medium	32%	3.5	813	196	617	$15.00	$17.60	$12.47	$0.00	$20.74	$26.43	$0.00	$92.24	$8.69	10.40%
Large	34%	5.6	1,395	336	1,059	$15.00	$27.95	$21.40	$0.00	$35.55	$45.36	$0.00	$145.26	$3.13	2.20%
XLg	37%	9.1	2,471	595	1,876	$15.00	$45.35	$37.91	$0.00	$62.95	$80.35	$0.00	$241.56	-$10.34	-4.10%
AnnAvg	32%	3.6	830	200	630	$15.00	$17.90	$12.73	$0.00	$21.16	$26.98	$0.00	$93.77	$8.61	10.11%
SumAvg	33%	4.1	983	237	747	$15.00	$20.70	$15.08	$0.00	$25.07	$31.99	$0.00	$107.84	$7.64	7.62%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

3. $5.00 Demand rate used for ease of comparison