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BEFORE THE ARIZONA CORPORATION COMMISSION

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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 OF 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 **STAFF'S NOTICE OF FILING DIRECT TESTIMONY**

Staff of the Arizona Corporation Commission ("Staff") hereby files the Direct Testimony of Elijah Abinah, Donna Mullinax, Barbara Keene, Howard Solganick Eric Van Epps and Candrea Allen in the above docket.

RESPECTFULLY SUBMITTED this 6th day of November 2015.

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Arizona Corporation Commission
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6th day of November 2015 with:

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BEFORE THE ARIZONA CORPORATION COMMISSION

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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.

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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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.

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[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.

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[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]

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[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

Professional Experience and Education
Donna H. Mullinax

- 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

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

(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	$ 270,189	$ 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

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

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

(Thousands of Dollars)

Line	Description	Original Cost			RCND		
		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 Staffs 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

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

Docket No. E-04204A-15-0142
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					(16,778)				
14	Regulatory Assets	-										
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								$ 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 Expense	(782,078)		(131,640)	(333,333)	(145,533)	(151,545)	(20,028)				
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

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

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)

		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)	Adjuatments (G)	Cash Working Capital (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	(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 (A)	Staff Adjustment (B)	Amount Per Staff (C)
	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

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

Docket No. E-04204A-15-0142
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

Test Year Ended December 31, 2014

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

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		$ 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		(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							
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	$ 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

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

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

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.
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		0.32396%
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

				Period Year		
Acct$Uns Gl Ferc	Account$$Desc$$Uns Gl Ferc	Account	Account$$Desc$$Uns Gl Account	2012	2013	2014
0440	Residential Sales	40000	Residential Revenue	(77,294,021.20)	(81,153,196.81)	(83,981,062.94)
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	3A

BAD DEBT

				Period Year		
Acct$Uns Gl Ferc	Account$$Desc$$Uns Gl Ferc	Account	Account$$Desc$$Uns Gl Account	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:	

		Total Company		ACC Jurisdictional	
FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT	DEBIT	CREDIT
926	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:	

FERC ACCT	FERC ACCOUNT DESCRIPTION	Total Company DEBIT	Total Company CREDIT	ACC Jurisdictional DEBIT	ACC Jurisdictional CREDIT
0548	Generation Expenses	26 $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	$30,486		$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	2B 4,016,660	5A 571,273	7D (236,550)	4,351,382 A
2014	2A 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 - 549
EX Type 010 - 039

	12 Months DEC-14			Ended DEC-13
Operations - Electric				
Production				
0546 Other Prod Oper-Supervision	0 00			612.28
0548 Generation Expenses	487 40	1,883.88		22,479.61
0549 Misc Other Pw Gen Exp	1 196.28			87.26
0557 Prod Expense-Other	0 00			37 02
Transmission				
0562 Trans-Station Expenses	197 369.06			78,915.50
0563 Trans-Overhead Line Exp	4,306.88	114,932.42		11,677.00
0566 Trans-Misc Oper Expense	3,256.48			0 00
Distribution				
0581 Dist-Load Dispatching	490,418.70			450,639.26
0582 Dist-Station Expenses	20.59			733.30
0583 Dist-Overhead Line Exp	133,378.82			121,802.57
0584 Dist-Underground Line Exp	180,004.94	1,366,009.24		181,531.54
0586 Dist-Meter Expenses	376,918.04	5,914.22	Incentive Comp	427,418.20
0587 Dist-Customer Install Ex	50,713.54	1,371,923.46		59,223 72
0588 Dist-Misc Expense	134,628.51			161 720 50
0589 Dist-Rent Expense	0.00			399 76
Customer Accounting				
0901 Cust Accounting-Supervision	137,792.83	631,549.23		126,989.23
0902 Meter Rea Expense	78,394.80	13,288.61	Incentive Comp	95,141.03
0903 Cust Rec/Collection Exp	417,362.40	644,838.84		416,491 76
Customer Service & Information				
0908 Customer Assistance Exp	18,719.38	180,190.92		58,934 49
0909 Informational/Instrct Adv Exp	181,858.90	6,962.23	Incentive Comp	18,542 94
0910 Misc Cust Service/Info Exp	1,611.68	186,153.16		1,053.38
Administration & General				
0925 Injuries & Damages	(10,090.13)	937,928.94		0 00
0920 A&G Salaries	C 900 489.61	75,753.83		741,072.29
0925 Injuries & Damages	40,078.36	-347,422.59		1,379 77
0926 Pensions & Benefits	7,351 10	666,160.18		6,884 31
0930 General Advertising Exp	0 00			1,009.28
Total Operations	3,232,194.43	2,983,883.73		2,994,566 64
Maintenance - Electric				
Production				
0553 Maint Gen & Elec Plant	151,028.81	210,220.56		166,887.89
0554 Maint of Misc Oth Pwr Gen Plant	59,191 74			45,309 11
Transmission				
0571 Trans-Maint of OH Lines	16 78 32	16,278.32		5 879 13
Distribution				
0592 Dist-Maint Stn Equip	297 374.69			360 493.69
0593 Dist-Maint of OH Lines	348 460 15	700,520 53		394,129 42
0594 Dist-Maint of UG Lines	47,134 45	3,660 72		48 944 66
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 4,016,080 18
		E 104,577 61	Total Incentive	
		4,263 789 44		
		347 422.59	A&G Capitalized	
		3 916 366 85		
Electric Plant Construction				
0107 Const Work In Progress	4,231,140.26	4,231 140.26		4 731,742.69
Electric Plant Removal		347,422 59		
0108 Acum Prov-Depre/Retr	63,204 10	4,578,562.85		38,953 77
Total Electric Payroll	8,453,558 19			8 783 358.64

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FERC	%	Adjustment
548	0.04%	77.05
562	2.93%	5,250.74
586	35.03%	62,784 40
901	16.47%	29,510.12
908	4 75%	8,518.07
920	17.01%	30,486.01
553	5.37%	9,620.49
571	0.42%	744.87
593	17.98%	32,229.99
	100.00%	179,227.74

UNSE(0142)000357

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Other Accounts			
0000 Unspecified			
0000 Unspecified	336,600.91		434,678.30
0417 Rev from Nonutility Oper	1,478,304.38	1,820,630.11	1,353,104.45
UNSE Payroll Charged to Affiliates	2,733.82		15,289.67
0000 Unspecified	25,932.57		31,298.37
0107 Const Work in Progress	178,248.99		53,410.75
0108 Accum Prov-De etr	0.00		2,721.87
0417 Rev from Nonutility Oper	0.00		328.16
0571 Trans-Maint of OH Lines	0.00		18.01
0580 Dist-Oper Supv & Engr	0.00		1,335.68
0583 Dist-Overhead Line Exp	0.00		8,801.84
0588 Dist-Misc Expense	8,538.69		6,371.41
0593 Dist-Maint of OH Lines	125.67	829,784.04	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	705.99		204.03
0878 Dist-Meter Exp	50,959.39		47,890.72
0880 Dist-Other Expenses	22,501.34		18,702.24
0887 Dist-Maint of Mains	2,358.24		4,838.41
0892 Dist-Maint of Services	4,104.39		5,283.31
0893 Dist-Maint of Meters	527.94		260.71
0902 Meter Reading Expense	42,434.53		29,948.93
0903 Cust Rec/Collection Exp	399,388.37		414,588.06
0908 Customer Assistance Ex	0.00		8,490.82
0920 A&G Salaries	47,429.51		74,538.67
0926 Pensions & Benefits	6,148.09		8,229.01
Total Payroll - Utility	11,102,979.34	11,102,979.34	11,332,986.36
		204,379.92	
		11,307,359.26	

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	1C 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. =
0.0778426335 6 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:	

		Total Company		ACC Jurisdictional	
FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT	DEBIT	CREDIT
0581	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

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*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	3,606
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		186,786.00	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	06/15/12	06/15/13		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 #282180-12GL	06/15/12	06/15/13		85,367.70	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 #282570-13GL	09/01/13	09/01/14		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	09/01/13	09/01/14		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 #	06/28/12	06/28/13		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 #	06/28/13	06/28/14		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	146,775.01
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	247,129.38	209,037.01

Reconciliation - 14010.0000

Preliminary Beg. Balance	279,418.82
Additions / Adjustments	-
Current Month Amortization	-32,289.39
EOM Balance	247,129.43
Balance s/b Rem. Prepaid	247,129.38
Variance	0.05

Other Items - Account 14100-0000	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 #071-004513-00 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	14,127.52	22,957.33
NEC Unified Solutions	11/28/12	8/31/14		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	5,008.63	5,008.63	5,008.63	5,008.57									20,034.46	-	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 081 - 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 084 - 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 081 - Ops & maint of substations	10/1/13	9/30/14		144,740.36										12,061.70	12,061.70	12,061.70	36,185.10	108,555.26	-
WAPA Agr #DSW-06DSR11910 - BC 082 - 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 084 - 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				128,558.08													-	-	-
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	34,050.41	34,050.41	34,050.40	34,050.35	34,150.54	34,150.53	34,150.54	34,150.54	34,150.53	24,695.20	24,695.20	45,122.21	401,466.86	527,681.83	169,462.71

Reconciliation - 14100.0000

Preliminary Beg. Balance	701,562.13
Additions / Adjustments	(128,558.08)
Current Month Amortization	-45,122.21
EOM Balance	527,881.84
Balance s/b Rem. Prepaid	527,881.83
Variance	0.01

Macintosh HD:Users:donnamullinax:ownCloud:Projects:Arizona UNS:DMS:Responses:Attachments:STF 10.14.xlsx UNSE 2013

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

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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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.

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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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]

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[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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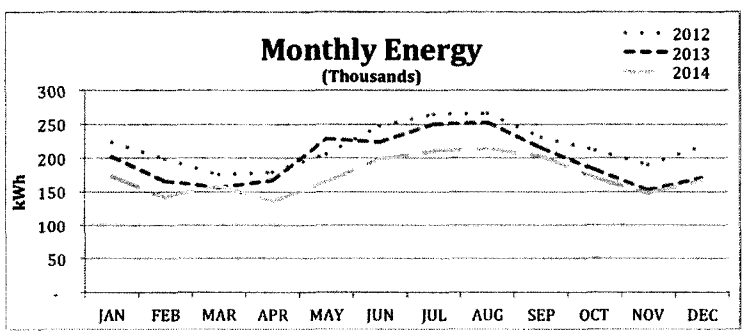
[17] Direct Testimony of Terry Nay, page 3, lines 14-24.
[18] 2013 BLS for Electric power generation, transmission and distribution (NAICS 2211), 50-249 employees.
[19] UNSE response to STF 3.01 through 3.12

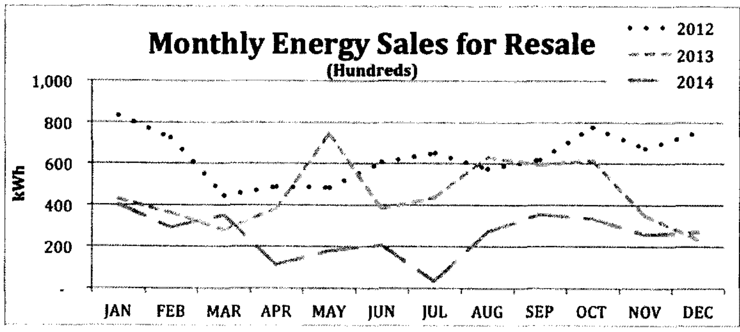
condition of the facility, storeroom, mobile equipment, and the yard. All of the locations and equipment observed during the field visits were in-place, appeared as described in the questionnaire responses, were reasonably maintained, and evidenced reasonable workmanship. Thus, all of the major rate 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.

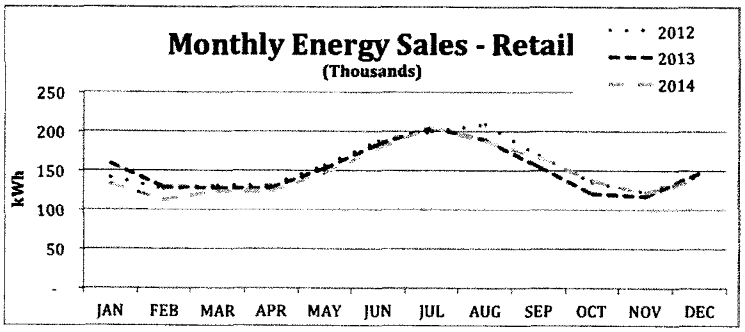
Q. What conclusions did you draw about the Company's peak demand, system energy, and the number and types of customers?

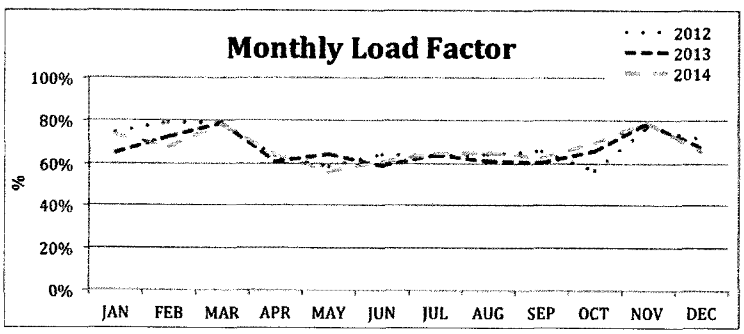
A. System energy and peak data were reviewed by month for the period 2012 through 2014.[20] Monthly load factors were calculated, and the data were plotted and examined. Data for individual customer classes were also examined, and the data plots were reviewed.[21] No unusual results were found. No specific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

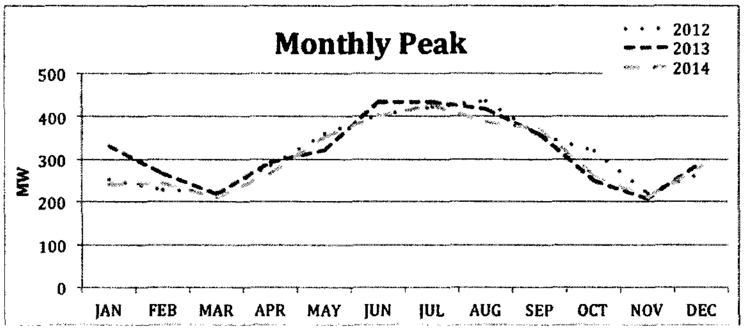


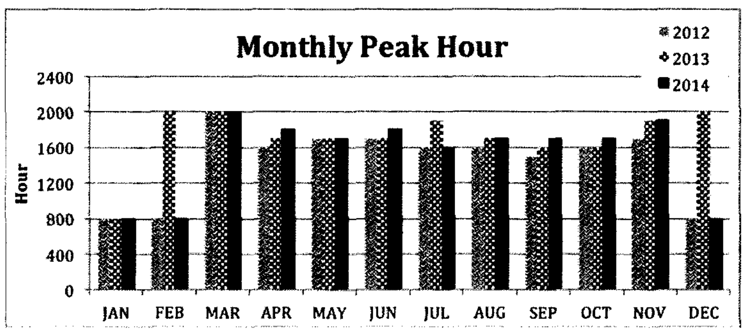
[20] UNSE FERC Form 1 page 401a
[21] UNSE response to STF 5.1


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

[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

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.

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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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
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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
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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