0000169261

Transcript Exhibit(s)

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

Exhibit #: UNSE 1-19

Part 6 of 8

For Part 7, see Barcode 0000169262

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
SUSAN BITTER SMITH - CHAIRMAN
BOB STUMP
BOB BURNS
DOUG LITTLE
TOM FORESE

EXHIBIT
UNSE-1
admitted

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-04204A-15-_____ **APPLICATION**

UNS Electric, Inc. ("UNS Electric" or "Company"), through undersigned counsel, and pursuant to A.R.S. §§ 40-250 and 40-251 and A.A.C. R14-2-103, hereby submits its Application for new rates to be effective no later than May 1, 2016. As proposed, the new rates are intended to result in an increase in retail revenues of approximately $3.5 million, or approximately 2.1% over adjusted test year retail revenues of $163,744,000.

Specifically, UNS Electric is requesting a $22.6 million increase to adjusted test year non-fuel revenues. 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% interest in Gila River Power Plant Unit 3 ("Gila River"), lower power market costs and adjustments to test year sales. UNS Electric'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 the $3.5 million retail revenue increase.

In addition, UNS Electric 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). As a result of these factors, UNS Electric's request would *decrease* revenue by approximately $5.8 million, or 3.6% less than adjusted test year retail revenues, in the first year after new rates take effect.

UNS Electric is also seeking approval of: (i) necessary modifications to its rate design; (ii) modifications to its PPFAC and Lost Fixed Cost Recovery mechanism ("LFCR"); (iii) updated depreciation rates and (iv) modifications to its Tariffs and Rules and Regulations.

In light of the significant updates to UNS Electric's rate design, the proposed revenue requirement and the PPFAC credit will result in the current average monthly bill for an average UNS Electric residential customer based on 983 kWh consumption in the summer and 669 kWh consumption in the winter to increase from $87.83 to $89.82 (a $1.99 increase) in year one and to increase by an additional $7.87 for subsequent years.

The Company's request is fully supported by the testimony, exhibits, and schedules submitted concurrently with this Application.

I. OVERVIEW.

UNS Electric's current rates were established in Decision No. 74235 (December 31, 2013), based on a test year ending June 30, 2012, with rates effective on January 1, 2014. As outlined below and as set forth in the supporting testimony, the Company has experienced several events that require it to file this rate case. Accordingly, UNS Electric is filing this rate case to: (i) enable it to continue to provide safe and reliable service; (ii) provide the company with an opportunity to recover its full cost of service, including an appropriate return on invested capital; and (iii) maintain or improve its credit rating, all of which will benefit UNS Electric and its customers.

The Company's proposals in this rate case will result in a decrease in retail revenues of approximately $5.8 million during the first year of new rates and an increase in retail revenues of approximately $3.5 million in subsequent years when compared to test year adjusted retail revenues. The difference in revenues between year one and subsequent years under the proposed rates reflects a proposed one-year credit to the PPFAC due to deferred savings from the

Company's interest in Gila River. The deferred savings arise from the accounting order approved by the Commission in Decision No. 74911 (January 22, 2015).

Although the Company's request would result in a reduction in retail revenues in the first year under the new rates, residential customers will experience an increase in monthly bills during the first year due to rate design proposals that are aimed at better matching rates to actual costs of service as well as reducing existing inter-class subsidies. Larger commercial customers will see somewhat reduced monthly bills both in year one and thereafter as part of the new rate design proposals intended to provide a more equitable sharing of fixed system costs.

A. Need for Increased Revenue Requirement.

In December 2014, UNS Electric acquired its interest in Gila River for approximately $55 million. The purchase price represents approximately 26 percent of the Company's original cost rate base established in the last rate case. The acquisition significantly benefits the Company and its customers by reducing the Company's reliance on the wholesale energy markets to serve its load. However, the ownership of Gila River has increased UNS Electric's non-fuel costs, and thus non-fuel base rates by approximately $12 million per year. This increase is expected to be offset by a decrease in purchased capacity and energy costs, and thus base fuel rates (approximately $12.3 million in 2015.) Beyond Gila River, UNS Electric invested $85 million since the last test year to upgrade and maintain its system to ensure continued reliable service to its 93,000 customers. Between its system investments and Gila River, UNS Electric's original cost rate base ("OCRB") has increased by $161 million over the prior test year.

B. Need for Updated Rate Design.

UNS Electric's test year retail sales are nearly 8% *below* the June 30, 2012 test year used in the Company's last rate case, due in part to a 50% reduction in sales to industrial and mining customers. Residential usage per customer fell nearly 4% between 2012 and 2014 and is expected to decline again in 2015. . The significant decline in sales is due to several factors, including: (i) the shutdown or curtailment of operations by certain large customers; (ii) the effects of increased energy efficiency ("EE") and distributed generation ("DG"); and (iii) the slow pace of economic recovery. Sales reductions resulting from successful EE measures and DG systems were exacerbated by business closures, including the 2014 bankruptcy of UNS Electric's largest customer.

The effect of lower overall sales means that the Company must recover its fixed costs over a small number of kilowatt-hours ("kWh"). Because a large portion of the Company's fixed costs are currently recovered volumetrically on a per-kWh basis, lower electricity sales contributes to a significant under-recovery of costs over time, particularly as the Company's cost of service increases. The ability to recover fixed costs through volumetric rates is compounded by an inclining block rate structure – where more of the fixed costs are collected at higher usage levels.

Although this historic rate design may have been appropriate in times of increasing customer usage and sales growth, this approach has created both difficulties for UNS Electric in recovering its authorized revenue requirement and inequities in recovering fixed costs from customers.

First, the Company is experiencing declining usage per customer. This trend, which is the result of many factors, results in significant under-recovery of fixed costs due the current rate structure that is heavily dependent on volumetric rates to recover fixed costs.

Second, a significant proportion of UNS Electric's residential and small general service customers have little to no volumetric usage. These customers include everything from seasonal homeowners, vacant structures and net metered rooftop PV systems, all of which seem more prevalent given the characteristics of the UNS Electric service area. Because of the volumetric rate design and the current net metering rules, a significant amount of fixed cost recovery is shifted from these extremely low volume usage customers to the other customers. These low-use/no-use customers are not paying an equitable share of the fixed costs to operate and maintain the UNS Electric grid to which they are connected and on which they are dependent to continue to receive safe and reliable electric service when needed.

Third, in addition to the fixed cost recoveries being shifted disproportionately to the customers using higher volumes of electricity, the Company is also suffering lost revenues because the LFCR is not designed to capture all of the lost fixed cost revenues associated with meeting the Commission's Renewable Energy Standard and Energy Efficiency Rules.

As a result, the Company is proposing changes to its rate design to help ensure that all customers pay a more equitable share of the fixed, ongoing costs of providing safe and reliable service. UNS Electric also is proposing to modify its net metering tariff to reduce the inequitable subsidies provided to net metered customers (which will also reduce future cost shifting). These proposed tariffs and rates will provide the Company with a better opportunity to recover its fixed costs and earn a reasonable return on its investment, as well as provide a more equitable allocation of costs among customers.

II. KEY ELEMENTS OF THE RATE CASE.

A. Revenue Requirement.

As set forth in the table below, UNS Electric is requesting a $22.6 million increase to test year adjusted non-fuel revenues. This increase will be offset by a proposed $14.9 million reduction in fuel cost and revenues due to the acquisition of Gila River, lower power market costs and adjustments to test year sales. UNS Electric's proposed base rates also will include $4.3 million in transmission costs currently being recovered through the TCA. In addition, UNS Electric is proposing a one-year credit to the 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). As a result of these factors, UNS Electric's request would decrease revenue by approximately $5.8 million, or 3.6%, in the first year after new rates take effect. In year two, after the deferred savings are fully credited, the Company's revenue would rise to a level that represents an increase of approximately $3.5 million, or 2.1%, over test year adjusted retail revenue.

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%

UNS Electric's revenue requirement increase is based on an OCRB of $272.0 million and a Replacement Cost New Less Depreciation ("RCND") rate base of $438.4 million, resulting in Fair Value Rate Base ("FVRB") of $355.7 million using a traditional 50/50 weighting of OCRB and RCND.

UNS Electric proposes to use its actual capital structure in determining the weighted average cost of capital ("WACC"). UNS Electric's actual test year capital structure is 52.83% equity and 47.17% debt.

UNS Electric's cost of long-term debt is 4.66% and required cost of common equity is 10.35%. The Company's WACC, based on these cost rates and the test year capital structure, is 7.67%.

UNS Electric is further proposing a fair value rate of return ("FVROR") of 6.22%. This FVROR is based on the methodology adopted by the Commission in several recent rate cases.

B. Gila River.

1. Impact on Rate Base and Operating Expenses.

The Company is adding its 25% interest in Gila River to its rate base. Gila River is the first and only Company-owned base load generating resource in UNS Electric's fleet. Ownership of Gila River provides numerous benefits to UNS Electric's customers, the most significant being long-term rate stability through the use of a highly efficient, combined cycle natural gas plant. The acquisition of Gila River is a prudent investment that will provide substantial benefits to customers and should be included in rate base because: (i) Gila River is a highly efficient generation resource suited to meet the Company's future load requirements, as well as provide firming capacity for intermittent renewable resources; (ii) as demonstrated from the RFP process, the cost of acquiring Gila River was significantly less expensive than other market acquisitions, as well as new build construction; and (iii) it is consistent with the Company's Integrated Resource Plan in that ownership of Gila River reduces the Company's reliance on the wholesale power markets, thus reducing risk to UNS Electric's customers by minimizing unpredictable swings in wholesale market costs.

The ownership of Gila River has increased UNS Electric's non-fuel costs, and thus non-fuel base rates by approximately $12 million per year. This increase is expected to be substantially offset by a decrease in purchased capacity and energy costs, and thus base fuel rates.

2. Accounting Order

In Decision No. 74991, the Commission acknowledged that the financial cost of acquiring and operating Gila River is substantial and may detrimentally impact the Company's financial position. It therefore authorized UNS Electric to defer certain costs and savings related to Gila River. The Company is proposing to return the deferred savings (which are anticipated to be $9.3 million) to customers through a PPFAC credit during the first year under the new rates. The Company is also proposing to recover the deferred costs over three years through base rates.

Further, the deferral of non-fuel costs will expire on April 30, 2016 and is limited to $10.5 million or the cumulative deferred savings at that date. As a result, the Company is seeking approval of rates effective as of May 1, 2016 in order to avoid incurring additional costs for Gila River beyond April 30, 2016 that may not be offset by related savings.

C. Depreciation Rates.

UNS Electric is proposing new depreciation rates based on an updated depreciation study. The new rates update depreciation rates approved by the Commission in Decision No. 71914

(September 30, 2010). The depreciation rates are lower for many asset accounts and result in a decrease in depreciation expense of $7.8 million. This decrease is offset in part due to an increase in depreciation related to the acquisition of Gila River.

D. Rate Design.

UNS Electric is proposing to continue its efforts to update and modernize its rate design. Through its proposals, the Company is seeking to better align rate design with cost causation and to reduce inter- and intra-class inequities. The rate structure meets our customers' evolving use of the electric system, reduces the level of cross-subsidies among customers and enhances the Company's ability to recover its fixed costs. The rate design will provide for a more equitable sharing of the cost of the UNS Electric infrastructure that is the backbone of providing safe and reliable service to all of its customers.

The Company's rate design proposals include: (i) increased basic service charges for both residential and small commercial customers; (ii) elimination of the third volumetric rate tier for residential customers; (iii) an optional three-part rate structure for residential and small commercial customers that includes a monthly service charge, a demand component and a volumetric energy component; and (iv) a mandatory three-part rate structure for partial requirements customers, including new users of solar arrays and other distributed generation equipment who use the electric system differently by "pushing" and "pulling" energy in ways that create new cost burdens and reliability concerns for the Company and its customers. In addition to the basic rate design proposals, UNS Electric also is proposing modified large commercial rates and new interruptible rates.

In order to incent business development and retention in its service area, UNS Electric has developed an Economic Development Rate. This rate will provide discounted electricity rates to new or existing businesses that meet certain qualifications, such as job creation or minimum load requirements.

Finally, in compliance with Decision No. 74689, UNS Electric also is submitting a pilot program for a "buy through" tariff that, if approved, would be available to Large Power Service customers.

E. Net Metering Tariff (Rider).

The Company is proposing to modify its net metering rider.[1] The new net metering rider will modify how new net metered customers receive credit for excess energy that is generated by their DG system and delivered to UNS Electric. The new rider would apply to net metered customers that submit applications for interconnection to UNS Electric's grid facilities after June 1, 2015.[2]

Under the new rider:

- New net metered customers would continue to receive a full retail rate offset for the energy they consume from their DG system;
- New net metered customers would pay the currently approved and applicable retail rate for all energy delivered by UNS Electric. The applicable retail rates will be limited to the demand based rate options; and
- New net metered customers would be compensated for any excess energy their DG system produces and delivers to UNS Electric with bill credits calculated using the Renewable Credit Rate (which is a rate that reflects the current cost of utility-scale solar energy). New net metered customers could carry over unused bill credits to future months if they exceed the amount of their current UNS Electric bill.

F. Adjustors.

UNS Electric in proposing modifications to its PPFAC and its LFCR. With respect to the PPFAC, the Company proposes to modify how the PPFAC rate is calculated. Presently, the PPFAC rate is adjusted monthly and charged to customers on a per kWh basis. The modified

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[1] The modifications are the same as set forth in its application in Docket No. E-04204A-15-0099 (that application was withdrawn on April 20, 2015).

[2] UNS Electric customers have been and will continue to be notified of the June 1, 2015 proposal to modify the net metering tariff through a disclaimer in its interconnection materials.

PPFAC will still be adjusted monthly but the adjustment will be based on a percentage change calculation. This approach will better align the changes in fuel costs with each rate classes' base fuel costs.

With respect to the LFCR, UNS Electric proposes to modify the LFCR, including adding recovery of fixed generation costs and 100% of non-generation demand charges (instead of 50%) as well as increasing the cap from 1% to 2%. The proposed changes will better address the impacts of the continuing expansion of the mandated renewable and energy efficiency programs.

G. Property Tax Deferral.

UNS Electric is requesting authority to defer 100% 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, UNS Electric 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 3 years.

H. Rules and Regulations.

The Company is proposing modifications to its Rules and Regulations and to its Tariffs. These modifications are intended to modernize UNS Electric's Rules and Regulations and to clarify areas in the Rules and Regulations that have caused undue confusion.

III. APPLICATION.

In support of this Application, UNS Electric respectfully states as follows:

A. The Company is a corporation duly organized, existing and in good standing under the laws of the State of Arizona. Its principal place of business is 2498 Airway Avenue, Kingman, Arizona 86409.

B. The Company is a public service corporation principally engaged in the generation, transmission and distribution of electricity for sale in Arizona pursuant to Certificates of Convenience and Necessity issued by the Commission.

C. All communications and correspondence concerning this Application, as well as communications and pleadings with respect thereto filed by other parties, should be served upon the following:

Bradley S. Carroll
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and

Michael W. Patten
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D. The Commission has jurisdiction to conduct public hearings to determine the fair value of the property of a public service corporation, to fix a just and reasonable rate of return thereon, and thereafter, to approve rate schedules designed to develop such return. Further, the Commission has jurisdiction to establish the practices and procedures to govern the conduct of such hearing, including, but not limited to, such matters as notice, intervention, filing, service, exhibits, discovery, and other prehearing and hearing matters.

E. Accompanying this Application are the standard filing requirements and rate design schedules described in A.A.C. R14-2-103. The Company also provides pre-filed direct testimonies and related exhibits from the following witnesses for UNS Electric supporting the requests made within the Application and schedules:

David Hutchens:	An overview of the Company's rate application and primary proposals, including the need for the modified rate design.
Terry Nay:	Overview of UNS Electric operations and capital expenditures.

Michael Sheehan	Acquisition of Gila River and related benefits and cost savings; and cost of facilities and operations, including cost of fuel and purchased power savings.
Carmine Tilghman	Scope of Company's investment in renewable generation resource, impact on utility operations, and the proposed Renewable Credit Rate.
Kentton Grant:	Overview of UNS Electric's financial condition; capital structure; cost of debt; and cost of credit support for fuel and purchased power procurement.
Ann Bulkley (CEA):	Cost of equity; fair value rate base; and fair value rate of return.
Dr. Ron White:	Depreciation methodology and rates.
Jason Rademacher:	Income tax and property tax.
David Lewis:	Revenue requirement, including rate base and income and expense adjustments; RCND; depreciation expense.
Dallas Dukes:	Requested revenue increase, proposed rate design changes, net metering rider modifications, and the proposed Economic Development Rate.
Craig Jones:	Cost of service study; proposed rate design; revisions to the base cost of fuel and purchased power; revisions to the Company's PPFAC and LFCR; and revisions to tariffs.
Denise Smith:	Revisions to UNS Electric's Rules and Regulations; Customer Service.

F. UNS Electric respectfully requests that this Commission set a date for a hearing on this Application such that new rates for the Company will become effective no later than May 1, 2016. At the hearing conducted pursuant to this rate request, UNS Electric will establish, among other things, that:

(1) its current rates and charges do not permit the Company to earn a fair return on the fair value of its assets devoted to public service, and that as a result, its current rates and charges are no longer just and reasonable;

(2) the requested revenue increase is the minimum amount necessary to allow the Company an opportunity to earn a fair return on the fair value of its assets devoted to public service, for preservation of the Company's financial integrity and for the attraction of new capital on reasonable terms, and is in the public interest;

(3) the Company's revenue request is reasonable and necessary for the Company to continue to provide adequate and reliable electric service to its customers as required by law and is in the public interest;

(4) the Company's request to return deferred savings related to Gila River to customers through a PPFAC credit during the first year under the new rates is in the public interest;

(5) the Company's request to recover deferred costs related to Gila River over three years through base rates is in the public interest;

(6) the inclusion of Gila River in rate base is in the public interest;

(7) the proposed tariffs and statement of charges proposed in the application are in the public interest;

(8) the proposed rate design will better align the fixed and variable costs of service with the rates paid by the customers causing those costs to be incurred and is in the public interest;

(9) the proposed modifications to the PPFAC will more equitably allocate PPFAC rates and is in the public interest;

(10) the proposed modifications to the LFCR will improve and more equitably allocate the recovery of lost fixed cost revenues resulting from DG, net metering and EE programs;

(11) the proposed revisions to the Company's Tariff (including its net metering tariff and any related waivers) and Rules and Regulations are in the public interest; and

(12) The proposed deferral of the recovery of the Gila River-related property taxes is in the public interest.

G. Further, UNS Electric requests that its next rate hearing be conducted in Tucson. UNS Electric's service territory includes both Santa Cruz County and Mohave County. Because its last three rate cases were conducted in Phoenix, UNS Electric believes it would be more equitable to its Santa Cruz County customers to have its next rate case hearing conducted in Tucson.

H. In addition to setting a hearing date, UNS Electric asks that the Commission issue a procedural order setting forth the prescribed public notice for the Application and establishing procedures for intervention, and appropriate discovery. UNS Electric further requests that the Company be authorized to serve all discovery requests, answers and objections electronically. Finally, UNS Electric requests that a procedural schedule be established, including a settlement track option, so that a final order in this case can be rendered and new rates can be effective by May 1, 2016.

WHEREFORE, UNS Electric respectfully requests that the Commission:

(1) issue a procedural order establishing a date for hearing evidence concerning the Application, prescribing the time and form of public notice to UNS Electric customers, establishing procedures for intervention and discovery as described above, and providing for a settlement track option for the docket;

(2) issue a final order finding and concluding that the Company's rate application is just and reasonable and granting new rates that result in an increase in retail revenues of approximately $3.5 million to allow it to recover its expenses and to have a reasonable opportunity to earn its authorized rate of return on its investment;

(3) issue a final order approving: (i) the return of deferred savings related to Gila River through a PPFAC credit during the first year under the new rates and (ii) the recovery of deferred costs related to Gila River over a three-year period through base rates;

(4) issue a final order approving the tariffs (including any related waivers) and statement of charges included with the Company's Application with an effective date no later than May 1, 2016;

(5) issue a final order approving the deferral of the recovery of the Gila River-related property taxes until the Company's next rate case;

(6) issue a final order approving the Company's revised Rules and Regulations; and

(7) grant the Company such additional relief as the Commission deems just and proper.

RESPECTFULLY SUBMITTED this 5th day of May 2015.

UNS ELECTRIC, INC.

By ______________________

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Attorneys for UNS Electric, Inc.

Original and 13 copies of the foregoing
filed this 5th day of May 2015, with:

Docket Control
Arizona Corporation Commission
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Copies of the foregoing hand-delivered/mailed
this 5th day of May 2015, to:

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By Jaclyn Howard

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 FOR RELATED APPROVALS.

DOCKET NO. E-04204A-15-______

EXHIBIT
UNSE-2
admitted

UNS ELECTRIC, INC.

SCHEDULES
"A" THROUGH "H"

VOLUME 4 of 4

MAY 5, 2015

Schedule

"A"

UNS Electric, Inc.
Computation of Increase in Gross Revenue Requirements
Test Year Ended December 31, 2014
(Thousands of Dollars)

Line No.	Description	ACC Jurisdiction Original Cost		RCND		Fair Value		Line No.
1	Adjusted Rate Base	$272,013	(a)	$439,427	(a)	$355,720		1
2	Adjusted Operating Income	$8,045	(b)	$8,045	(b)	$8.045		2
3	Current Rate of Return (2/1)	2.96%		1.83%		2.26%		3
4	Required Operating Income	$22,108		$22,108		$22.108		4
5	Weighted Average Cost of Capital	7.67%	(c)	7.67%		7.67%		5
6	Fair Value Adjustment	0.46%		-2.64%		-1.45%		6
7	Required Rate of Return (4/1)	8.13%	(c)	5.03%		6.22%		7
8	Operating Income Deficiency	$14,064		$14,064		$14.064		8
9	Gross Revenue Conversion Factor	1.6084	(d)	1.6084	(d)	1.6084	(d)	9
10	Increase in Gross Revenue Requirement	$22,621		$22,621		$22,621		10

Line No.	Customer Classification	Proposed Net Increase / Decrease To Adjusted Test Year (e)		% Dollar Increase / Decrease to Adjusted Test Year (e)	Line No.
11	Residential	$20,557		5.46%	11
12	Small General Service	2,664		0.00%	12
13	Large General Service	9,228		7.42%	13
14	Large Light and Power	(9,973)		2.19%	14
15	Lighting Service	76		13.16%	15
16	Total	$22,552	(1)	11.91%	16

(1) Test Year Billed Margin Revenues calculated $69K more than Booked Revenues.

Supporting Schedules
(a) B-1
(b) C-1
(c) D-1
(d) C-3
(e) H-1

UNS Electric, Inc.
Summary Results of Operations
Prior Years Ended December 31, 2012 and 2013, Test Year Ended December 31, 2014
and Projected Year Ended December 31, 2015
(Thousands of Dollars)

Line No.	Description	Prior Years Ended December 31, 2012 (a)	2013 (a)	Test Year Ended December 31, 2014 Actuals (b)	Adjusted (b)	Projected Year Ended December 31, 2015 Present Rates (c)	Proposed Rates (c)	Line No.
1	Operating Revenues	$205,026	$189,630	$191,772	$148,935	$190,675	$203,406	1
2	Operating Expenses (includes income taxes)	180,784	170,870	174,554 (2)	133,514	171,654	169,744	2
3	Operating Income	24,242	18,760	17,218	15,421	19,021	33,662	3
4	Other Income and Deductions	91	830	(264)	(264)	(478)	(478)	4
5	Income Before Interest Expense	24,333	19,590	16,954	15,157	18,543	33,184	5
6	Interest Expense	7,479	6,837	7,720 (2)	7,720	5,950	8,763	6
7	Net Income	$16,854	$12,753	$9,234	$7,437	$12,593	$24,421	7
8	Earnings Per Average Common Share (1)	N/A (1)	N/A	N/A	N/A	N/A	N/A	8
9	Dividends Per Common Share (1)	N/A (1)	N/A	N/A	N/A	N/A	N/A	9
10	Payout Ratio (1)	0% (1)	0%	0%	0%	0%	0%	10
11	Return on Year-End Invested Capital	8.92%	7.11%	5.30%	4.76%	5.16%	9.23%	11
12	Return on Average Invested Capital	9.03%	7.15%	5.69%	5.11%	5.47%	9.79%	12
13	Return on Year-End Common Equity	11.81%	8.76%	4.86%	3.95%	6.46%	12.31%	13
14	Return on Average Common Equity	12.09%	8.85%	5.50%	4.46%	6.54%	12.31%	14
15	Times Total Interest Earned - Before Income Taxes	4.70	3.81	3.61	2.94	4.22	5.40	15
16	Times Total Interest Earned - After Income Taxes	3.25	2.87	2.20	1.96	3.12	3.79	16

(1) UNS Electric, Inc. is a subsidiary of UniSource Energy Corporation and has no publicly traded stock; thus such information is not meaningful.
(2) Includes reclassification of $7 thousand for Customer Deposit Interest Expense from Other Interest Expense to Other O&M Expense.

Supporting Schedules
(a) E-2
(b) C-1
(c) F-1

UNS Electric, Inc.
Summary of Capital Structure
Prior Years Ended December 31, 2012 and 2013, Test Year Ended December 31, 2014
and Projected Year Ended December 31, 2015
(Thousands of Dollars)

Line No.	Description	Prior Years Ended December 31, 2012 (a)	Prior Years Ended December 31, 2013 (a)	Test Year Ended December 31, 2014 Actuals (a)	Projected Year December 31, 2015 Present Rates (b)	Projected Year December 31, 2015 Proposed Rates	Line No.
	Capitalization						
1	Short-Term Debt	$0	$0	$0	$0	$0	1
2	Long-Term Debt - Net (1)	129,226	129,408	129,590	$169,590	169,590	2
	Total Debt	129,226	129,408	129,590	169,590	169,590	
3	Common Stock Equity	142,761	145,601	189,932	189,932	189,932	3
4	Total Capital	$271,987	$275,009	$319,522	$359,522	$359,522	4
	Capitalization Ratios						
5	Short-Term Debt	0.00%	0.00%	0.00%	0.00%	0.00%	5
6	Long-Term Debt - Net	47.51%	47.06%	47.17%	47.17%	47.17%	6
7	Common Stock Equity	52.49%	52.94%	52.83%	52.83%	52.83%	7
8	Total Capital	100.00%	100.00%	100.00%	100.00%	100.00%	8
9	Weighted Cost of Short-Term Debt	0.00%	0.00%	0.00%	0.00%	0.00%	9
10	Weighted Cost of Long-Term Debt	2.29%	2.27%	2.27%	2.27%	2.20%	10
11	Weighted Cost of Common Equity	5.43%	5.48%	5.47%	5.47%	5.47%	11

(1) The balance of Long-Term Debt is stated net of the unamortized balance of debt discount and issuance expense.

Supporting Schedules
(a) E-1
(b) D-1

UNS Electric, Inc.
Construction Expenditures and Gross Utility Plant in Service
Prior Years Ended December 31, 2012 and 2013, Test Year Ended December 31, 2014
and Projected Years Ended December 31, 2013, 2014 and 2015
(Thousands of Dollars)

Line No.	Year		Construction Expenditures	Net Plant Placed in Service	Gross Utility Plant in Service	Line No.
1	Prior Year Ended December 31, 2012	(a)	$38,554	$294,187	$528,721	1
2	Prior Year Ended December 31, 2013	(a)	$56,278	$328.223	$573,896	2
3	Test Year Ended December 31, 2014	(a)	$93,270	$398,468	$677,488	3
4	Projected Year Ended December 31, 2015	(b)	$37,684	$387,873	$693,409	4
5	Projected Year Ended December 31, 2016	(b)	$36,607	$403.302	$732,553	5
6	Projected Year Ended December 31, 2017	(b)	$39,156	$412,756	$765,395	6

Supporting Schedules
(a) E-1 & E-3
(b) F-3

UNS Electric, Inc.
Summary Changes in Financial Position
Prior Years Ended December 31, 2012 and 2013, Test Year Ended December 31, 2014
and Projected Year Ended December 31, 2015
(Thousands of Dollars)

Line No.	Description	Prior Years Ended December 31,		Test Year Ended December 31, 2014	Projected Year Ended December 31, 2015		Line No.
		2012 (a)	2013(a)	2014 (a)	Present Rates (b)	Proposed Rates (b)	
1	Net Cash Flows from Operating Activities	$49,537	$43,313	$43,468	$47,644	$31,504	1
2	Net Cash Flows From Investing Activities	(36,595)	(59,293)	(96,990)	(42,410)	(42,410)	2
3	Net Cash Flows from Financing Activities	(9,812)	12,939	54,117	(1,300)	14,840	3
4	Net Increase (Decrease) in Cash	$3,130	($3,041)	$595	$3,934	$3,934	4

Supporting Schedules
(a) E-3
(b) F-2

Schedule

"B"

UNS Electric, Inc.
Summary of Original Cost and RCND Rate Base
Test Year Ended December 31, 2014
(Thousands of Dollars)

Line No.	Description	Total: Adjusted Original Cost Rate Base (a)	Total: Adjusted RCND Rate Base (b)	ACC Jurisdiction: Adjusted Original Cost Rate Base (a)	ACC Jurisdiction: Adjusted RCND Rate Base (b)	Line No.
1	Gross Utility Plant in Service	$787,729	$1.353,145	$664,701	$1,169,067	1
2	Less: Accumulated Depreciation	324,457	600,536	296,961	561,911	2
3	Net Utility Plant in Service	463,272	752,609	367,740	607,156	3
4	Citizens Acquisition Discount	(108,563)	(196,364)	(95,156)	(170,847)	4
5	Less: Accum. Amort. - Citizens Acq. Discount	(40,810)	(79,269)	(36,098)	(69,678)	5
6	Net Citizens Acquisition Discount	(67,753)	(117,095)	(59,058)	(101,169)	6
7	Total Net Utility Plant	395,519	635,514	308,682	505,987	7
8	Customer Advances for Construction	(3,833)	(4,268)	(3,833)	(4,268)	8
9	Customer Deposits	(4,428)	(4,428)	(4,428)	(4,428)	9
10	Other (ITC)	(422)	(422)	(422)	(422)	10
11	Accumulated Deferred Income Taxes	(36,819)	(67,663)	(35,161)	(64,617)	11
12	Total Deductions	(45,502)	(76,781)	(43,844)	(73,735)	12
13	Allowance for Working Capital	7,500	7,500	7,175	7,175	13
14	Regulatory Assets	0	0	0	0	14
15	Regulatory Liabilities	0	0	0	0	15
16	Total Rate Base	$357,517	$566,233	$272,013	$439,427	16

Supporting Schedules
(a) B-2
(b) B-3

Recap Schedules
A-1

UNS Electric, Inc.
Pro Forma Adjustments to Original Cost Rate Base
Total Company and ACC Jurisdiction
Test Year Ended December 31, 2014
(Thousands of Dollars)

			Total Company			ACC			
Line No.	Description		Actual at End of Test Period	Total Adjustments (a)	Adjusted at End of Test Period	Unadjusted Test Year	Total Adjustments (c)	ACC Jurisdiction	Line No.
1	Gross Utility Plant in Service		$786,152	$1,577	$787,729	$663,252	$1,449	$664,701	1
2	Less: Accumulated Depreciation		323,817	640	324,457	296,355	606	296,961	2
3	Net Utility Plant in Service		462,335	937	463,272	366,897	843	367,740	3
4	Citizens Acquisition Discount		(115,671)	7,108	(108,563)	(101,088)	5,932	(95,156)	4
5	Less: Accum. Amort. - Citizens Acq. Discount		(44,797)	3,987	(40,810)	(39,625)	3,527	(36,098)	5
6	Net Citizens Acquisition Discount		(70,874)	3,121	(67,753)	(61,463)	2,405	(59,058)	6
7	Total Net Utility Plant		391,461	4,058	395,519	305,434	3,248	308,682	7
8	Customer Advances for Construction		(3,833)	0	(3,833)	(3,833)	0	(3,833)	8
9	Customer Deposits		(4,428)	0	(4,428)	(4,428)	0	(4,428)	9
10	Other (ITC)		(4,695)	4,273	(422)	(4,695)	4,273	(422)	10
11	Accumulated Deferred Income Taxes		(34,962)	(1,857)	(36,819)	(33,387)	(1,774)	(35,161)	11
12	Total Deductions		(47,918)	2,416	(45,502)	(46,343)	2,499	(43,844)	12
13	Allowance for Working Capital	(b)	14,074	(6,574)	7,500	13,469	(6,294)	7,175	13
14	Regulatory Assets		0	0	0	0	0	0	14
15	Regulatory Liabilities		0	0	0	0	0	0	15
16	Total Original Cost Rate Base		$357,617	($100)	$357,517	$272,560	($547)	$272,013	16

Supporting Schedules
(a) B-2 (P2-3)
(b) B-5

Recap Schedules
B-1

UNS Electric, Inc.
Pro Forma Adjustments to **Original Cost Rate Base**
Test Year Ended December 31, 2014
(Thousands of Dollars)

Line No.	Description	Acquisition Discount Adjustment	Accumulated Deferred ITC	Accumulated Deferred Income Taxes	Fortis Rate Base Adjustment	Gila River Adjustment	ARO	Working Capital	Total Page Adjustments	Line No.
1	Gross Utility Plant in Service	$0	$0	$0	($10)	$2,750	($1,163)	$0	$1,577	1
2	Less: Accumulated Depreciation	0	0	0	(0)	700	(60)	0	640	2
3	Net Utility Plant in Service	0	0	0	(10)	2,050	(1,103)	0	937	3
4	Citizens Acquisition Discount	9,156	0	0	0	(2,048)	0	0	7,108	4
5	Less: Accum. Amort. - Citizens Acq. Discount	3,989	0	0	0	(2)	0	0	3,987	5
6	Net Citizens Acquisition Discount	5,167	0	0	0	(2,046)	0	0	3,121	6
7	Total Net Utility Plant	5,167	0	0	(10)	4	(1,103)	0	4,058	7
8	Customer Advances for Construction	0	0	0	0	0	0	0	0	8
9	Customer Deposits	0	0	0	0	0	0	0	0	9
10	Other (ITC)	0	4,273	0	0	0	0	0	4,273	10
11	Accumulated Deferred Income Taxes	0	0	(1,857)	0	0	0	0	(1,857)	11
12	Total Deductions	0	4,273	(1,857)	0	0	0	0	2,416	12
13	Allowance for Working Capital	0	0	0	0	0	0	(6,574)	(6,574)	13
14	Regulatory Assets	0	0	0	0	0	0	0	0	14
15	Regulatory Liabilities	0	0	0	0	0	0	0	0	15
16	Total Original Cost Rate Base	$5,167	$4,273	($1,857)	($10)	$4	($1,103)	($6,574)	($100)	16

Supporting Schedules
N/A

Recap Schedules
B-1

UNS Electric, Inc.
Pro Forma Adjustments to **ACC Jurisdiction Rate Base**
Test Year Ended December 31, 2014
(Thousands of Dollars)

Line No.	Description	Acquisition Discount Adjustment	Accumulated Deferred ITC	Accumulated Deferred Income Taxes	Fortis Rate Base Adjustment	Gila River Adjustment	ARO	Working Capital	Total Page Adjustments	Line No.
1	Gross Utility Plant in Service	$0	$0	$0	($10)	$2,622	($1,163)	$0	$1,449	1
2	Less: Accumulated Depreciation	0	0	0	(0)	667	(61)	0	606	2
3	Net Utility Plant in Service	0	0	0	(10)	1,955	(1,102)	0	843	3
4	Citizens Acquisition Discount	7,900	0	0	0	(1,968)	0	0	5,932	4
5	Less: Accum. Amort. - Citizens Acq. Discount	3,529	0	0	0	(2)	0	0	3,527	5
6	Net Citizens Acquisition Discount	4,371	0	0	0	(1,966)	0	0	2,405	6
7	Total Net Utility Plant	4,371	0	0	(10)	(11)	(1,102)	0	3,248	7
8	Customer Advances for Construction	0	0	0	0	0	0	0	0	8
9	Customer Deposits	0	0	0	0	0	0	0	0	9
10	Other (ITC)	0	4,273	0	0	0	0	0	4,273	10
11	Accumulated Deferred Income Taxes	0	0	(1,774)	0	0	0	0	(1,774)	11
12	Total Deductions	0	4,273	(1,774)	0	0	0	0	2,499	12
13	Allowance for Working Capital	0	0	0	0	0	0	(6,294)	(6,294)	13
14	Regulatory Assets	0	0	0	0	0	0	0	0	14
15	Regulatory Liabilities	0	0	0	0	0	0	0	0	15
16	Total Original Cost Rate Base	$4,371	$4,273	($1,774)	($10)	($11)	($1,102)	($6,294)	($547)	16

Supporting Schedules
N/A

Recap Schedules
B-1

UNS Electric, Inc.
Pro Forma Adjustments to **RCND Rate Base**
Test Year Ended December 31, 2014
(Thousands of Dollars)

Line No.	Description	Total Company			ACC Jurisdiction			Line No.
		Actual at End of Test Period (a), (b)	Total Adjustments (c)	Adjusted at End of Test Period	Unadjusted Test Year	Total Adjustments	ACC Jurisdiction	
1	Gross Utility Plant in Service	$1,351,568	$1,577	$1,353,145	$1,167,618	$1,449	$1,169,067	1
2	Less: Accumulated Depreciation	599,897	639	600,536	561,304	607	561,911	2
3	Net Utility Plant in Service	751,671	938	752,609	606,314	842	607,156	3
4	Citizens Acquisition Discount	(211,594)	15,230	(196,364)	(183,758)	12,911	(170,847)	4
5	Less: Accum. Amort. - Citizens Acq. Discount	(86,802)	7,533	(79,269)	(76,308)	6,630	(69,678)	5
6	Net Citizens Acquisition Discount	(124,792)	7,697	(117,095)	(107,450)	6,281	(101,169)	6
7	Total Net Utility Plant	626,879	8,635	635,514	498,864	7,123	505,987	7
8	Customer Advances for Construction	(4,268)	0	(4,268)	(4,268)	0	(4,268)	8
9	Customer Deposits	(4,428)	0	(4,428)	(4,428)	0	(4,428)	9
10	Other (ITC)	(4,695)	4,273	(422)	(4,695)	4,273	(422)	10
11	Accumulated Deferred Income Taxes	(64,250)	(3,413)	(67,663)	(61,357)	(3,260)	(64,617)	11
12	Total Deductions	(77,641)	860	(76,781)	(74,748)	1,013	(73,735)	12
13	Allowance for Working Capital	14,074	(6,574)	7,500	13,469	(6,294)	7,175	13
14	Regulatory Assets	0	0	0	0	0	0	14
					0			
15	Regulatory Liabilities	0	0	0	0	0	0	15
16	Total RCND Rate Base	$563,312	$2,921	$566,233	$437,585	$1,842	$439,427	16

Supporting Schedules
(a) B-4
(b) B-2
(c) B-3 (P2-3)

Recap Schedules
B-1

UNS Electric, Inc.
Pro Forma Adjustments to RCND Rate Base
Test Year Ended December 31, 2014
(Thousands of Dollars)

Line No.	Description	Acquisition Discount Adjustment	Accumulated Deferred ITC	Accumulated Deferred Income Taxes	Fortis Rate Base Adjustment	Gila River Adjustment	ARO	Working Capital	Total Page Adjustments	Line No.
1	Gross Utility Plant in Service	$0	$0	$0	($10)	$2,750	($1,163)	$0	$1,577	1
2	Less: Accumulated Depreciation	0	0	0	(0)	700	(61)	0	639	2
3	Net Utility Plant in Service	0	0	0	(10)	2,050	(1,102)	0	938	3
4	Citizens Acquisition Discount	17,278	0	0	0	(2,048)	0	0	15,230	4
5	Less: Accum. Amort. - Citizens Acq. Discount	7,535	0	0	0	(2)	0	0	7,533	5
6	Net Citizens Acquisition Discount	9,743	0	0	0	(2,046)	0	0	7,697	6
7	Total Net Utility Plant	9,743	0	0	(10)	4	(1,102)	0	8,635	7
8	Customer Advances for Construction	0	0	0	0	0	0	0	0	8
9	Customer Deposits	0	0	0	0	0	0	0	0	9
10	Other (ITC)	0	4,273	0	0	0	0	0	4,273	10
11	Accumulated Deferred Income Taxes	0	0	(3,413)	0	0	0	0	(3,413)	11
12	Total Deductions	0	4,273	(3,413)	0	0	0	0	860	12
13	Allowance for Working Capital	0	0	0	0	0	0	(6,574)	(6,574)	13
14	Regulatory Assets	0	0	0	0	0	0	0	0	14
15	Regulatory Liabilities	0	0	0	0	0	0	0	0	15
16	Total RCND Rate Base	$9,743	$4,273	($3,413)	($10)	$4	($1,102)	($6,574)	$2,921	16

Supporting Schedules
N/A

Recap Schedules
B-1

UNS Electric, Inc.
Pro Forma Adjustments to **RCND ACC Jurisdiction**
Test Year Ended December 31, 2014

Line No.	Description	Acquisition Discount Adjustment	Accumulated Deferred ITC	Accumulated Deferred Income Taxes	Fortis Rate Base Adjustment	Gila River Adjustment	ARO	Working Capital	Total Page Adjustments	Line No.
1	Gross Utility Plant in Service	$0	$0	$0	($10)	$2,622	($1,163)	$0	$1,449	1
2	Less: Accumulated Depreciation	0	0	0	(0)	668	(61)	0	607	2
3	Net Utility Plant in Service	0	0	0	(10)	1,954	(1,102)	0	842	3
4	Citizens Acquisition Discount	14,879	0	0	0	(1,968)	0	0	12,911	4
5	Less: Accum. Amort. - Citizens Acq. Discount	6,632	0	0	0	(2)	0	0	6,630	5
6	Net Citizens Acquisition Discount	8,247	0	0	0	(1,966)	0	0	6,281	6
7	Total Net Utility Plant	8,247	0	0	(10)	(12)	(1,102)	0	7,123	7
8	Customer Advances for Construction	0	0	0	0	0	0	0	0	8
9	Customer Deposits	0	0	0	0	0	0	0	0	9
10	Other (ITC)	0	4,273	0	0	0	0	0	4,273	10
11	Accumulated Deferred Income Taxes	0	0	(3,260)	0	0	0	0	(3,260)	11
12	Total Deductions	0	4,273	(3,260)	0	0	0	0	1,013	12
13	Allowance for Working Capital	0	0	0	0	0	0	(6,294)	(6,294)	13
14	Regulatory Assets	0	0	0	0	0	0	0	0	14
15	Regulatory Liabilities	0	0	0	0	0	0	0	0	15
16	Total RCND Rate Base	$8,247	$4,273	($3,260)	($10)	($12)	($1,102)	($6,294)	$1,842	16

Supporting Schedules
N/A

Recap Schedules
B-1

UNS Electric, Inc.
RCND By Major Plant Accounts
Test Year Ended December 31, 2014
(Thounsands of Dollars)

Line No.	Function	Plant Account	Description	RCN	Percent	RCND	Line No.	RCN Accum Depr
			Utility Plant In Service					
1	INTANGIBLE	302	Franchises & Consents	$0	N/A	$0	1	$0
2		303	Misc. Intangible Plant	13,174	62.8%	8,267	2	$4,907
3			Total Intangible Plant	13,174		8,267	3	4,907
4	OTHER PRODUCTION	340	Land & Land Rights	268	100.0%	268	4	0
5		341	Structures & Improvements	10,609	79.8%	8,462	5	2,147
6		342	Fuel Holders, Producers, & Accessories	5,270	73.3%	3,865	6	1,405
7		343	Prime Movers	99,856	74.2%	74,082	7	25,774
8		344	Generators	108,843	84.4%	91,994	8	16,849
9		345	Accessory Electric Equipment	25,531	80.8%	20,625	9	4,906
10		346	Misc. Power Plant Equipment	18,507	84.8%	15,685	10	2,822
11		347	ARO Other Production	1,163	94.8%	1,102	11	61
12			Total Other Production	270,147		216,083	12	54,064
13	TRANSMISSION (Non-EHV)	350	Land & Land Rights	11,723	99.5%	11,668	13	55
14		352	Structures & Improvements	1,804	76.8%	1,385	14	419
15		353	Station Equipment	69,711	71.3%	49,689	15	20,022
16		354	Towers & Fixtures	1,694	354.6%	6,008	16	(4,314)
17		355	Poles & Fixtures	61,060	75.5%	46,086	17	14,974
18		356	Overhead Conductors & Devices	34,354	83.2%	28,573	18	5,781
19		358	Underground Conductors & Devices	50	81.0%	40	19	10
20		359	Roads & Trails	704	44.5%	313	20	391
21			Total Transmission Plant	181,100		143,762	21	37,338
22	DISTRIBUTION	360	Land & Land Rights	1,423	95.5%	1,359	22	64
23		361	Structures & Improvements	11,233	62.0%	6,965	23	4,268
24		362	Station Equipment	119,068	57.5%	68,405	24	50,663
25		364	Poles, Towers, & Fixtures	191,099	27.8%	53,105	25	137,994
26		365	Overhead Conductors & Devices	160,145	39.5%	63,279	26	96,866
27		366	Underground Conduit	33,178	54.7%	18,134	27	15,044
28		367	Underground Conductors & Devices	94,063	47.7%	44,850	28	49,213
29		368	Line Transformers	177,466	40.9%	72,643	29	104,823
30		369	Services	30,555	44.3%	13,528	30	17,027
31		370	Meters	11,433	108.3%	12,380	31	(947)
32		373	Street Lights and Signal Systems	9,642	31.4%	3,029	32	6,613
33			Total Distribution Plant	839,305		357,677	33	481,628

Supporting Schedules
N/A

Recap Schedules
B-3

UNS Electric, Inc.
RCND By Major Plant Accounts
Test Year Ended December 31, 2014

Line No.	Function	Plant Account	Description	RCN	Percent	RCND	Line No.	RCN Accum Depr
34	GENERAL	389	Land & Land Rights	758	100.0%	758	34	0
35		390	Structures & Improvements	8,171	76.8%	6,272	35	1,899
36		391	Office Furniture & Equipment	3,656	48.5%	1,773	36	1,883
37		392	Transportation Equipment	15,743	25.3%	3,976	37	11,767
38		393	Stores Equipment	513	54.2%	278	38	235
39		394	Tools, Shop, & Garage Equipment	3,768	50.3%	1,894	39	1,874
40		395	Laboratory Equipment	1,942	66.2%	1,286	40	656
41		396	Power Operated Equipment	5,119	63.5%	3,253	41	1,866
42		397	Communication Equipment	7,992	78.4%	6,267	42	1,725
43		398	Miscellaneous Equipment	180	69.3%	125	43	55
44			Total General Plant	47,842		25,882	44	21,960
45			Total Plant	$1,351,568		$751,671	45	$599,897

Supporting Schedules
N/A

Recap Schedules
B-3

UNS Electric, Inc.
RCND By Major Plant Accounts
Test Year Ended December 31, 2014
(Thousands of Dollars)

Line No.	Function	Plant Account	Description	RCN	Percent	RCND	Line No.	RCN Accum Depr
			Acquisition Discount					
1	INTANGIBLE	302	Franchises & Consents	$0	0.0%	$0	1	$0
2		303	Misc. Intangible Plant	(3,728)	51.9%	(1,935)	2	(1,793)
3			Total Intangible Plant	(3,728)		(1,935)	3	(1,793)
4	OTHER PRODUCTION	340	Land & Land Rights	(430)	100.0%	(430)	4	(0)
5		341	Structures & Improvements	(804)	94.5%	(760)	5	(44)
6		342	Fuel Holders, Producers, & Accessories	(959)	86.5%	(829)	6	(130)
7		343	Prime Movers	(16,805)	92.1%	(15,470)	7	(1,335)
8		344	Generators	(3,901)	92.2%	(3,595)	8	(306)
9		345	Accessory Electric Equipment	(2,027)	83.7%	(1,697)	9	(330)
10		346	Misc. Power Plant Equipment	(711)	88.7%	(631)	10	(80)
11			Total Other Production	(25,637)		(23,412)	11	(2,225)
12	TRANSMISSION (Non-EHV)	350	Land & Land Rights	(704)	96.5%	(680)	12	(24)
13		352	Structures & Improvements	(59)	66.6%	(40)	13	(19)
14		353	Station Equipment	(12,026)	68.3%	(8,211)	14	(3,815)
15		354	Towers & Fixtures	(4,668)	46.7%	(2,181)	15	(2,487)
16		355	Poles & Fixtures	(4,037)	45.6%	(1,841)	16	(2,196)
17		356	Overhead Conductors & Devices	(5,794)	69.9%	(4,052)	17	(1,742)
18		358	Underground Conductors & Devices	0	0.0%	0	18	0
19		359	Roads & Trails	(199)	77.4%	(154)	19	(45)
20			Total Transmission Plant	(27,487)		(17,159)	20	(10,328)
21	DISTRIBUTION	360	Land & Land Rights	(643)	99.0%	(637)	21	(6)
22		361	Structures & Improvements	(2,337)	65.4%	(1,528)	22	(809)
23		362	Station Equipment	(17,154)	51.0%	(8,742)	23	(8,412)
24		364	Poles, Towers, & Fixtures	(45,524)	55.1%	(25,105)	24	(20,419)
25		365	Overhead Conductors & Devices	(28,561)	54.4%	(15,541)	25	(13,020)
26		366	Underground Conduit	(6,717)	55.9%	(3,751)	26	(2,966)
27		367	Underground Conductors & Devices	(11,871)	45.9%	(5,449)	27	(6,422)
28		368	Line Transformers	(25,352)	47.7%	(12,096)	28	(13,256)
29		369	Services	(6,952)	55.7%	(3,874)	29	(3,078)
30		370	Meters	(3,473)	64.9%	(2,253)	30	(1,220)
31		373	Street Lights and Signal Systems	(2,282)	52.2%	(1,192)	31	(1,090)
32			Total Distribution Plant	(150,866)		(80,168)	32	(70,698)

Supporting Schedules
N/A

Recap Schedules
B-3

UNS Electric, Inc.
RCND By Major Plant Accounts
Test Year Ended December 31, 2014
(Thousands of Dollars)

Line No.	Function	Plant Account	Description	RCN	Percent	RCND	Line No.	RCN Accum Depr
33	GENERAL	389	Land & Land Rights	(32)	100.0%	(32)	33	0
34		390	Structures & Improvements	(1,019)	72.9%	(742)	34	(277)
35		391	Office Furniture & Equipment	(538)	2.8%	(15)	35	(523)
36		392	Transportation Equipment	(2)	0.0%	(2)	36	0
37		393	Stores Equipment	(59)	67.8%	(40)	37	(19)
38		394	Tools, Shop, & Garage Equipment	(1,198)	59.2%	(709)	38	(489)
39		395	Laboratory Equipment	(363)	72.0%	(261)	39	(102)
40		396	Power Operated Equipment	(198)	40.6%	(80)	40	(118)
41		397	Communication Equipment	(442)	51.5%	(228)	41	(214)
42		398	Miscellaneous Equipment	(25)	37.2%	(9)	42	(16)
43			Total General Plant	(3,876)		(2,118)	43	(1,758)
44			Total Plant	($211,594)		($124,792)	44	($86,802)

Supporting Schedules
N/A

Recap Schedules
B-3

UNS Electric, Inc.
Computation of Working Capital
Test Year Ended December 31, 2014
(Thousands of Dollars)

Line No.	Description	Total Company			ACC Jurisdiction	Line No.
		Original Cost	RCND Cost	Total		
1	Cash Working Capital	($5,431)	($5,431)	($5,431)	($5,198)	1
2	Fuel Inventory	290	290	290	276	2
3	Materials and Supplies	11,861	11,861	11,861	11,353	3
4	Prepayments	780	780	780	744	4
5	Total Working Capital Allowance	$7,500	$7,500	$7,500	$7,175	5

Supporting Schedules
B-5 (P2)

Recap Schedules
B-1

UNS Electric, Inc.
Detail of Adjustments to Working Capital
Test Year Ended December 31, 2014
(Thousands of Dollars)

Line No.	Description	Actual	Adjustments: Thirteen Month Average	Adjustments: Cash Working Capital	Total Company Adjusted	ACC Jurisdiction	Line No.
1	Cash Working Capital	$0	N/A	($5,431)	($5,431)	($5,198)	1
2	Fuel Inventory (Account 151)	290	0	N/A	290	276	2
3	Materials & Supplies (Accounts 154 and 163)	13,368	(1,507)	N/A	11,861	11,353	3
4	Prepayments (Account 165)	416	364	N/A	780	744	4
5	Total	$14,074	($1,143)	($5,431)	$7,501	$7,175	5

Supporting Schedules
B-5 (P3)

Recap Schedules
B-5 (P1)

UNS Electric, Inc.
Cash Working Capital - Lead/Lag Study
Test Year Ended December 31, 2014
(Thousands of Dollars)

Line No.	Description (A)	Pro Forma Test Year Amount (B)	Revenue Lag Days (C)	Expense Lag Days (D)	Net Lag Days (Col. C - Col. D) (E)	Lead/Lag Factor (Col. E/365) (F)	Cash Working Capital Required (Col. F x Col. B) (G)	Line No.
	Operating Expenses							
	Non-Cash Expenses							
1	Bad Debts Expense	$506						1
2	Depreciation	11,406						2
3	Amortization	(3,629)						3
4	Deferred Income Taxes	4,627						4
	Other Operating Expenses							
5	Salaries and Wages (UNSE Direct Employees)	4,616	35.59	23.33	12.26	0.0336	$155	5
6	Incentive Pay (UNSE Direct Employees)	329	35.59	267.00	(231.41)	(0.6340)	(209)	6
7	Purchased Power	62,965	35.59	33.79	1.80	0.0049	309	7
8	Transmission Other	9,014	35.59	40.67	(5.08)	(0.0139)	(125)	8
9	Meter Reading	574	35.59	33.67	1.92	0.0053	3	9
10	Customer Records & Collection Expenses (excluding allocations)	1,169	35.59	34.94	0.65	0.0018	2	10
11	Office Supplies and Expenses	1,005	35.59	50.89	(15.30)	(0.0419)	(42)	11
12	Injuries and Damages	750	35.59	70.52	(34.93)	(0.0957)	(72)	12
13	Pensions and Benefits	1,960	35.59	51.37	(15.78)	(0.0432)	(85)	13
14	Support Services - TEP (Direct Labor, Burdens, System Alloc.)	6,059	35.59	44.77	(9.18)	(0.0252)	(152)	14
15	Property Taxes	6,733	35.59	212.00	(176.41)	(0.4820)	(3,245)	15
16	Payroll Taxes	376	35.59	12.00	23.59	0.0646	24	16
17	Current Income Taxes	0	35.59	0.00	35.59	0.0975	0	17
18	Interest on Customer Deposits	7	35.59	182.50	(146.91)	(0.4025)	(3)	18
19	Other Operations and Maintenance	25,050	35.59	41.21	(5.62)	(0.0154)	(386)	19
20	Total Operating Expenses	$133,517				-		20
	Other Cash Working Capital Elements:							
21	Interest On Long-Term Debt	7,859	35.59	89.50	(53.91)	(0.1477)	(1,161)	21
22	Revenue Taxes and Assessments	11,717	35.59	49.43	(13.84)	(0.0379)	(444)	22
23	Total Cash Working Capital					Total Company	($5,431)	23
						ACC Jurisdiction	($3,919)	

Supporting Schedules
N/A

Recap Schedules
B-2, B-3

Schedule

"C"

UNS Electric, Inc.
Adjusted Test Year Income Statement
Test Year Ended December 31, 2014
(Thousands of Dollars)

Line No.	Description	Total Company: Unadjusted (a)	Total Company: Pro Forma Adjustments (b)	Total Company: Adjusted	ACC Jurisdction: Unadjusted	ACC Jurisdction: Pro Forma Adjustments	ACC Jurisdction: ACC Jurisdiction	Line No.
	Operating Revenues							
1	Electric Retail Revenues	$167,999	($20,892)	$147,107	$167,999	($20,892)	$147,107	1
2	Sales for Resale	12,285	(12,285)	0	12,285	(12,285)	(0)	2
3	Other Operating Revenue	11,488	(9,660)	1,828	11,488	(9,660)	1,828	3
4	Total Operating Revenues	191,772	(42,837)	148,935	191,772	(42,837)	148,935	4
	Operating Expenses							
5	Fuel, Purchased Power and Transmission	107,290	(29,768)	77,522	107,290	(29,768)	77,522	5
6	Other Operations and Maintenance Expense	32,011 (1)	(2,893)	29,118	31,034	11,834	42,868	6
7	Depreciation and Amortization	22,847	(7,812)	15,035	19,684	(6,624)	13,060	7
8	Taxes Other than Income Taxes	5,940	1,272	7,212	5,256	893	6,149	8
9	Income Taxes	6,466	(1,839)	4,627	6,465	(5,174)	1,291	9
10	Total Operating Expenses	174,554	(41,040)	133,514	169,729	(28,839)	140,890	10
11	Operating Income	$17,218	($1,797)	$15,421	$22,043	($13,998)	$8,045	11
	Other Income and Deductions							
12	Allowance for Equity Funds	$98						
13	Other - Net	(362)						
14	Total Other Income and Deductions	(264)						
15	Income Before Interest Expense	16,954						
	Interest Expense							
16	Interest on Long-Term Debt	7,622						
17	Other Interest Expense	323 (1)						
18	Allowance for Borrowed Funds	(225)						
19	Total Interest Expense	7,720						
20	Income Before Cumulative Effect of Accounting Change	9,234						
21	Cumulative Effect of Accounting Change - Net of Tax	0						
22	Net Income Available for Common Stock	$9,234						

(1) Includes reclassification of $7 thousand for Customer Deposit Interest Expense From Other Interest Expense to Other O&M Expense,

Supporting Schedules	Recap Schedules
(a) E-2	A-1
(b) C-2	A-2

UNS Electric, Inc.
Income Statement Pro Forma Adjustments - Total Company
Test Year Ended December 31, 2014
(Thousands of Dollars)

Line No.	Description	LFCR	Non-Retail Rev, Fuel & Purchase Power	Customer & Weather Adjustment	Purchased Power and Fuel Adjustment	REST & DSM	Payroll Expense	Total Page Adjustments	Line No.
	Operating Revenues								
1	Electric Retail Revenues	$0	$0	($6,022)	($14,870)	$0	$0	($20,892)	1
2	Sales for Resale	0	(12,285)	0	0	0	0	(12,285)	2
3	Other Operating Revenue	(1,378)	0	0	0	(8,331)	0	(9,709)	3
4	Total Operating Revenues	(1,378)	(12,285)	(6,022)	(14,870)	(8,331)	0	(42,886)	4
	Operating Expenses								
5	Fuel, Purchased Power and Transmission	0	(12,285)	0	(14,870)	(2,613)	0	(29,768)	5
6	Other Operations and Maintenance Expense	0	0	0	0	(4,184)	179	(4,005)	6
7	Depreciation and Amortization	0	0	0	0	0	0	0	7
8	Taxes Other than Income Taxes	0	0	0	0	(0)	0	(0)	8
9	Income Taxes	0	0	0	0	0	0	0	9
10	Total Operating Expenses	0	(12,285)	0	(14,870)	(6,797)	179	(33,773)	10
11	Operating Income	($1,378)	$0	($6,022)	$0	($1,534)	($179)	($9,113)	11

Supporting Schedules
N/A

Recap Schedules
C-1

UNS Electric, Inc.
Income Statement Pro Forma Adjustments - Total Company
Test Year Ended December 31, 2014
(Thousands of Dollars)

Line No.	Description	Payroll Tax Expense	Pension & Benefits	Retiree Medical	Rate Case Expense	Bad Debt Expense	Depr & Amort Expense	Total Page Adjustments	Line No.
	Operating Revenues								
1	Electric Retail Revenues	$0	$0	$0	$0	$0	$0	$0	1
2	Sales for Resale	0	0	0	0	0	0	0	2
3	Other Operating Revenue	0	0	0	0	0	0	0	3
4	Total Operating Revenues	0	0	0	0	0	0	0	4
	Operating Expenses								
5	Fuel, Purchased Power and Transmission	0	0	0	0	0	0	0	5
6	Other Operations and Maintenance Expense	0	128	39	56	(358)	0	(135)	6
7	Depreciation and Amortization	0	0	0	0	0	(7,812)	(7,812)	7
8	Taxes Other than Income Taxes	14	0	0	0	0	0	14	8
9	Income Taxes	0	0	0	0	0	0	0	9
10	Total Operating Expenses	14	128	39	56	(358)	(7,812)	(7,933)	10
11	Operating Income	($14)	($128)	($39)	($56)	$358	$7,812	$7,933	11

Supporting Schedules	Recap Schedules
N/A	C-1

UNS Electric, Inc.
Income Statement Pro Forma Adjustments - Total Company
Test Year Ended December 31, 2014
(Thousands of Dollars)

Line No.	Description	Property Tax	Incentive Compensation	Injuries & Damages	Membership Dues	Gila River Deferred Cost	Service Fees	Total Page Adjustments	Line No.
	Operating Revenues								
1	Electric Retail Revenues	$0	$0	$0	$0	$0	$0	$0	1
2	Sales for Resale	0	0	0	0	0	0	0	2
3	Other Operating Revenue	0	0	0	0	0	95	95	3
4	Total Operating Revenues	0	0	0	0	0	95	95	4
	Operating Expenses								
5	Fuel, Purchased Power and Transmission	0	0	0	0	0	0	0	5
6	Other Operations and Maintenance Expense	0	167	370	(11)	3,100	0	3,626	6
7	Depreciation and Amortization	0	0	0	0	0	0	0	7
8	Taxes Other than Income Taxes	1,252	8	0	0	0	0	1,260	8
9	Income Taxes	0	0	0	0	0	0	0	9
10	Total Operating Expenses	1,252	175	370	(11)	3,100	0	4,886	10
11	Operating Income	($1,252)	($175)	($370)	$11	($3,100)	$95	($4,791)	11

Supporting Schedules	Recap Schedules
N/A	C-1

UNS Electric, Inc.
Income Statement Pro Forma Adjustments - Total Company
Test Year Ended December 31, 2014
(Thousands of Dollars)

Line No.	Description	Fortis Acquisition Costs	Other Revenue	Gila O&M and Outages	Income Taxes	Total Page Adjustments	Total Adjustments	Line No.
	Operating Revenues							
1	Electric Retail Revenues	$0	$0	$0	$0	$0	($20,892)	1
2	Sales for Resale	0	0	0	0	0	(12,285)	2
3	Other Operating Revenue	0	(46)	0	0	(46)	(9,660)	3
4	Total Operating Revenues	0	(46)	0	0	(46)	(42,837)	4
	Operating Expenses							
5	Fuel, Purchased Power and Transmission	0	0	0	0	0	(29,768)	5
6	Other Operations and Maintenance Expense	(5,749)	0	3,371	0	(2,379)	(2,893)	6
7	Depreciation and Amortization	0	0	0	0	0	(7,812)	7
8	Taxes Other than Income Taxes	(2)	0	0	0	(2)	1,272	8
9	Income Taxes	0	0	0	(1,839)	(1,839)	(1,839)	9
10	Total Operating Expenses	(5,751)	0	3,371	(1,839)	(4,220)	(41,040)	10
11	Operating Income	$5,751	($46)	($3,371)	$1,839	$4,174	($1,797)	11

Supporting Schedules
N/A

Recap Schedules
C-1

UNS Electric, Inc.
Income Statement Pro Forma Adjustments - **ACC Jurisdiction**
Test Year Ended December 31, 2014
(Thousands of Dollars)

Line No.	Description	LFCR	Non-Retail Rev, Fuel & Purchase Power	Customer & Weather Adjustment	Purchased Power and Fuel Adjustment	REST & DSM	Payroll Expense	Total Adjustments	Line No.
	Operating Revenues								
1	Electric Retail Revenues	$0	$0	($6,022)	($14,870)	$0	$0	($20,892)	1
2	Sales for Resale	0	(12,285)	0	0	0	0	(12,285)	2
3	Other Operating Revenue	(1,378)	0	0	0	(8,331)	0	(9,709)	3
4	Total Operating Revenues	(1,378)	(12,285)	(6,022)	(14,870)	(8,331)	0	(42,886)	4
	Operating Expenses								
5	Fuel, Purchased Power and Transmission	0	(12,285)	0	(14,870)	(2,613)	0	($29,768)	5
6	Other Operations and Maintenance Expense	0	0	0	0	(4,181)	172	(4,009)	6
7	Depreciation and Amortization	0	0	0	0	0	0	0	7
8	Taxes Other than Income Taxes	0	0	0	0	(0)	0	(0)	8
9	Income Taxes	0	0	0	0	0	0	0	9
10	Total Operating Expenses	0	(12,285)	0	(14,870)	(6,794)	172	(33,777)	10
11	Operating Income	($1,378)	$0	($6,022)	$0	($1,537)	($172)	($9,109)	11

Supporting Schedules
N/A

Recap Schedules
C-1

UNS Electric, Inc.
Income Statement Pro Forma Adjustments - **ACC Jurisdiction**
Test Year Ended December 31, 2014
(Thousands of Dollars)

Line No.	Description	Payroll Tax Expense	Pension & Benefits	Retiree Medical	Rate Case Expense	Bad Debt Expense	Depr & Amort Expense	Total Adjustments	Line No.
	Operating Revenues								
1	Electric Retail Revenues	$0	$0	$0	$0	$0	$0	$0	1
2	Sales for Resale	0	0	0	0	0	0	0	2
3	Other Operating Revenue	0	0	0	0	0	0	0	3
4	Total Operating Revenues	0	0	0	0	0	0	0	4
	Operating Expenses								
5	Fuel, Purchased Power and Transmission	0	0	0	0	0	0	0	5
6	Other Operations and Maintenance Expense	0	123	37	53	(358)	0	(145)	6
7	Depreciation and Amortization	0	0	0	0	0	(6,624)	(6,624)	7
8	Taxes Other than Income Taxes	13	0	0	0	0	0	13	8
9	Income Taxes	0	0	0	0	0	0	0	9
10	Total Operating Expenses	13	123	37	53	(358)	(6,624)	(6,756)	10
11	Operating Income	($13)	($123)	($37)	($53)	$358	$6,624	$6,756	11

Supporting Schedules
N/A

Recap Schedules
C-1

UNS Electric, Inc.
Income Statement Pro Forma Adjustments - **ACC Jurisdiction**
Test Year Ended December 31, 2014
(Thousands of Dollars)

Line No.	Description	Property Tax	Incentive Compensation	Injuries & Damages	Membership Dues	Gila River Deferred Cost	Service Fees	Total Page Adjustments	Line No.
	Operating Revenues								
1	Electric Retail Revenues	$0	$0	$0	$0	$0	$0	$0	1
2	Sales for Resale	0	0	0	0	0	0	0	2
3	Other Operating Revenue	0	0	0	0	0	95	95	3
4	Total Operating Revenues	0	0	0	0	0	95	95	4
	Operating Expenses								
5	Fuel, Purchased Power and Transmission	0	0	0	0	0	0	0	5
6	Other Operations and Maintenance Expense	0	162	356	(11)	3,100	0	3,607	6
7	Depreciation and Amortization	0	0	0	0	0	0	0	7
8	Taxes Other than Income Taxes	874	7	0	0	0	0	881	8
9	Income Taxes	0	0	0	0	0	0	0	9
10	Total Operating Expenses	874	169	356	(11)	3,100	0	4,488	10
11	Operating Income	($874)	($169)	($356)	$11	($3,100)	$95	($4,393)	11

Supporting Schedules
N/A

Recap Schedules
C-1

UNS Electric, Inc.
Income Statement Pro Forma Adjustments - **ACC Jurisdiction**
Test Year Ended December 31, 2014
(Thousands of Dollars)

Line No.	Description	Fortis Acquisition Costs	Other Revenue	Gila O&M and Outages	Income Taxes	OATT	Total Page Adjustments	Total Adjustments	Line No.
	Operating Revenues								
1	Electric Retail Revenues	$0	$0	$0	$0	$0	$0	($20,892)	1
2	Sales for Resale	0	0	0	0	0	0	(12,285)	2
3	Other Operating Revenue	0	(46)	0	0	0	(46)	(9,660)	3
4	Total Operating Revenues	0	(46)	0	0	0	(46)	(42,837)	4
	Operating Expenses								
5	Fuel, Purchased Power and Transmission	0	0	0	0	0	0	(29,768)	5
6	Other Operations and Maintenance Expense	(5,521)	0	3,371	0	14,531	12,381	11,834	6
7	Depreciation and Amortization	0	0	0	0	0	0	(6,624)	7
8	Taxes Other than Income Taxes	(1)	0	0	0	0	(1)	893	8
9	Income Taxes	0	0	0	(5,174)	0	(5,174)	(5,174)	9
10	Total Operating Expenses	(5,522)	0	3,371	(5,174)	14,531	7,206	(28,839)	10
11	Operating Income	$5,522	($46)	($3,371)	$5,174	($14,531)	($7,252)	($13,998)	11

Supporting Schedules
N/A

Recap Schedules
C-1

UNS Electric, Inc.
Computation of Gross Revenue Conversion Factor
Test Year Ended December 31, 2014

Line No.	Description	Percentage of Incremental Gross Revenues		Line No.
1	Gross Revenue	100.00%		1
2	Less: Uncollectible Revenue	0.3438%		2
3	Taxable Income as a Percent	99.66%		3
4	Less: Federal and State Income Taxes (Combined Effective Tax Rate = 37.613%)	37.48%		4
5	Change in Net Operating Income	62.17%		5
6	Gross Revenue Conversion Factor	1.6084	(a)	6

(a) Line No. 1 divided by line No. 5.

Supporting Schedules	Recap Schedules
N/A	A-1

Schedule

"D"

UNS Electric, Inc.
Summary Cost of Capital
Test Year Ended December 31, 2014
(Thousands of Dollars)

Line No.	Capital Source		Capitalization Amount		Capitalization Percent	Cost Rate	Weighted Cost of Capital (c)	Line No.
	Actual - End of Test Period							
1	Debt	(a)	169,590	(1)	47.17%	4.82%	2.27%	1
2	Common Equity	(b)	189,932		52.83%	10.35%	5.47%	2
3	Total Capital		$359,522		100.00%		7.74%	3
	Proposed - End of Test Period							
4	Debt	(a)	$169,590		47.17%	4.66%	2.20%	4
5	Common Equity		189,932		52.83%	10.35%	5.47%	5
6	Total Capital		$359,522		100.00%		7.67%	6

(1) The balance of Long-Term Debt is stated net of the unamortized balance of debt discount and issuance expense.

Supporting Schedules
(a) D-2
(b) E-1

Recap Schedules
(c) A-3

UNS Electric, Inc.
Summary Cost of Capital
Projected Period Ended December 31, 2015
(Thousands of Dollars)

Line No.	Capital Source		Capitalization Amount	Capitalization Percent	Cost Rate	Weighted Cost of Capital (b)	Line No.
	Projected as of December 31, 2015						
1	Debt	(a)	178,895	47.80%	4.66%	2.23%	1
2	Common Equity		195,071	52.20%	10.35%	5.40%	2
3	Total Capital		$373,967	100.00%		7.63%	3

Supporting Schedules
(a) D-2

Recap Schedules
(b) A-3

UNS Electric, Inc.
Cost of Long-Term Debt and Short-Term Debt
Test Year Ended December 31, 2014
(Thousands of Dollars)

Line No.	Description		End of Test Period (Actual) Outstanding	Annual Interest	Cost Rate		End of Test Period (Proposed) Outstanding	Annual Interest	Cost Rate	Line No.
	Fixed Rate Debt									
1	6.500% Senior Unsecured Notes due 08/15		$50,000	$3,250			$0	$0		1
2	7.100% Senior Unsecured Notes Series B due 08/23		50,000	3,550			50,000	3,550		2
3	3.220% Senior Unsecured Notes Series A due 08/27		0	0		(1)	80,000	2,576		3
4	3.950% Senior Unsecured Notes Series B due 04/45		0	0		(1)	50,000	1,975		4
5	Total Fixed Rate Debt		100,000	6,800	6.80%		180,000	8,101	4.50%	5
	Variable Rate Debt									
6	4-Year Term Loan due 08/15	(2)	30,000	629			0	0		6
7	Total Variable Rate Debt		30,000	629	2.10%		0	0	N/A	7
8	Total Long-Term Debt	(a)	$130,000	$7,429	5.71%		$180,000	$8,101	4.50%	8
	Unamortized Debt Discount, Premium and									
9	Expense and Loss on Reacquired Debt		(410)			(3)	(1,246)			9
	Amortization of Debt Discount and									
10	Expense and Loss on Reacquired Debt			182				169		10
11	Credit Facility Commitment Fees			51		(4)		63		11
12	Total Long-Term Debt - Net		$129,590	$7,662	5.91%		$178,754	$8,333	4.66%	12
13	Total Short-Term Debt	(5)	$40,000	$513	1.28%		$0	$0	N/A	13
14	Total Debt - Net		$169,590	$8,175	4.82%		$178,754	$8,333	4.66%	14

(1) In April 2015, UNS Electric entered into a note purchase agreement for $130 million aggregate principal amount of senior notes in two separate series
(2) 4-Year Term Loan interest rate = LIBOR + 1.125%, with LIBOR = 0.97% based on a fixed-for-floating interest rate swap expiring in August 2015.
(3) Unamortized Debt Discount Expense from new issuances includes placement agents fees, rating agency fees, and estimated legal fees.
(4) Credit Facility Commitment Fees of $63K reflects a 0.125% annual commitment fee on 50% of the $100 million credit facility shared with UNS Gas.
(5) Annual interest calculated using period-end revolver balance and 1-month LIBOR rate plus a credit spread of 1.125%

Supporting Schedules
(a) E-1 (P2)
E-9

Recap Schedules
A-4

UNS Electric, Inc.
Cost of Long-Term Debt and Short-Term Debt
Projected Period Ended December 31, 2015
(Thousands of Dollars)

Line No.	Description		Projected Period Ended December 31, 2015 Outstanding	Annual Interest	Cost Rate	Line No.
	Fixed Rate Debt					
1	7.100% Senior Unsecured Notes Series B due 08/23		$50,000	$3,550		1
2	3.220% Senior Unsecured Notes Series A due 08/27	(1)	80,000	$2,576		2
3	3.950% Senior Unsecured Notes Series B due 04/45	(1)	50,000	$1,975		3
4	Total Fixed Rate Debt		180,000	8,101	4.50%	4
	Variable Rate Debt					
5	4-Year Term Loan due 08/15		0	0		5
6	Total Variable Rate Debt		0	0	N/A	6
7	Total Long-Term Debt		$180,000	$8,101	4.50%	7
8	Unamortized Debt Discount, Premium and Expense and Loss on Reacquired Debt		(1,105)			8
9	Amortization of Debt Discount and Expense and Loss on Reacquired Debt			169		9
10	Credit Facility Commitment Fees		(2)	63		10
11	Total Long-Term Debt - Net		$178,895	$8,333	4.66%	11
12	Total Short-Term Debt		$0	$0	N/A	12
13	Total Debt - Net		$178,895	$8,333	4.66%	13

(1) In April 2015, UNS Electric entered into a note purchase agreement for $130 million aggregate principal amount of senior notes in two separate series
(2) Credit Facility Commitment Fees of $63K reflects a 0.125% annual commitment fee on 50% of the $100 million credit facility shared with UNS Gas.

Supporting Schedules	Recap Schedules
N/A	D-1

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

No preferred stock was outstanding during the test year.

No preferred stock is expected to be issued.

Supporting Schedules	Recap Schedules
N/A	N/A

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

The cost of common equity requested by UNS Electric is 10.35%.

Supporting Schedules	Recap Schedules
N/A	D-1

Schedule

"E"

UNS Electric, Inc.
Comparative Balance Sheets
Test Year Ended December 31, 2014 and Prior Years Ended December 31, 2013 and 2012
(Thousands of Dollars)

Line No.	Description	2014	2013	2012	Line No.
	(a) Utility Plant				
1	Plant in Service	$786,152	$655,079	$602,101	1
2	Construction Work in Progress	6,116	20,707	28,574	2
3	Plant Held for Future Use	891	891	827	3
4	Plant Under Capital Leases	0	0	0	4
5	Acquisition Discount	(115,671)	(102,781)	(102,781)	5
6	Total Utility Plant	677,488	573,896	528,721	6
7	Accumulated Depreciation and Amortization	(323,817)	(286,806)	(272,020)	7
8	Accumulated Amortization - Capital Leases	0	0	0	8
9	Accumulated Amort. - Acquisition Discount	44,797	41,133	37,486	9
10	Total Utility Plant - Net	398,468	328,223	294,187	10
	Other Property and Investments				
11	Non-Utility Property	788	788	788	11
12	Long-Term Portion of Derivative Assets	0	0	0	12
13	Long-Term Portion of Derivative Assets - Hedges	213	336	2,110	13
14	Total Other Property and Investments	1,001	1,124	2,898	14
	Current Assets				
15	Cash and Cash Equivalents	5,607	5,012	4,053	15
16	Special Deposits & Working Funds	49	47	52	16
17	Temporary Cash Investments	0	0	4,000	17
18	Accounts Receivable - Retail Customers	11,577	12,026	11,343	18
19	Accounts Receivable - Other	278	422	1,674	19
20	Allowance for Doubtful Accounts	(1,624)	(1,142)	(1,073)	20
21	Accrued Unbilled Revenues	7,535	7,789	7,189	21
22	Intercompany Accounts Receivable	925	858	200	22
23	Material and Supplies	13,658	11,645	11,100	23
24	Prepayments	416	843	948	24
25	Derivative Instrument Assets	525	2,403	881	25
26	Other	559	401	208	26
27	Total Current Assets	39,505	40,304	40,575	27
	Regulatory & Other Assets				
28	Other Regulatory Assets	37,964	20,860	22,908	28
29	Unamortized Debt Discount and Expense	410	592	774	29
30	Accumulated Deferred Income Taxes	25,841	15,207	11,407	30
31	Other	833	563	546	31
32	Total Deferred Debits	65,048	37,222	35,635	32
33	Total Assets	$504,022	$406,873	$373,295	33

Supporting Schedules
(a) E-5
E-9

Recap Schedules
A-4

UNS Electric, Inc.
Comparative Balance Sheets
Test Year Ended December 31, 2014 and Prior Years Ended December 31, 2013 and 2012
(Thousands of Dollars)

Line No.	Description	2014	2013	2012	Line No.
	Capitalization				
1	Common Stock	$0	$0	$0	1
2	Additional Paid-In Capital	123,887	78,887	78.887	2
3	Accumulated Earnings	66.119	66,885	64.132	3
4	Accumulated Other Comprehensive Income	(74)	(171)	(258)	4
5	Total Common Stock Equity	189,932	145,601	142,761	5
		0			
6	Long-Term Debt	130,000	130,000	130,000	6
7	Total Capitalization	319,932	275,601	272,761	7
		0			
	Current Liabilities	0			
8	Accounts Payable - Net	49,581	33,775	12.886	8
9	Intercompany Payables - Net	4.560	3,859	6.160	9
10	Interest Accrued	2,803	2,786	2,794	10
11	Income Taxes Accrued	0	0	0	11
12	Other Taxes Accrued	2,990	2,840	2.503	12
13	Customer Deposits	4,428	6,266	6.163	13
14	Derivative Instrument Liabilities	14,863	1,256	6,613	14
15	Other	5,661	5,425	3,455	15
16	Total Current Liabilities	84,886	56,207	40,574	16
	Deferred Credits and Other Liabilities				
17	Customer Advances for Construction	3,833	4,225	7,716	17
18	Other Regulatory Liabilities	20,227	14,314	6,206	18
19	Accumulated Deferred Income Taxes	65,497	50,656	37.998	19
20	Other	9,648	5,871	8.040	20
21	Total Deferred Credits and Other Liabilities	99,205	75,066	59,960	21
22	Total Liabilities and Stockholders' Equity	$504,023	$406,874	$373,295	22

Supporting Schedules
E-9

Recap Schedules
A-3

UNS Electric, Inc.
Comparative Income Statements
Test Year Ended December 31, 2014 and Prior Years Ended December 31, 2013 and 2012
(Thousands of Dollars)

Line No.	Description	2014	2013	2012	Line No.
	(a) Operating Revenues				
1	Electric Retail Revenues	$167,999	$160,651	$160,107	1
2	Sales for Resale	12,285	18,627	31,801	2
3	Other Operating Revenue	11,488	10,352	13,118	3
4	Total Operating Revenues	191,772	189,630	205,026	4
	(a) Operating Expenses				
5	Fuel, Purchased Power & Transmission	107,290	108,000	116,139	5
6	Other Operations and Maintenance Expense	32,004	30,158	29,576	6
7	Depreciation and Amortization	22,847	20,345	19,530	7
8	Taxes Other than Income Taxes	5,940	5,898	4,727	8
9	Income Taxes	6,466	6,469	10,812	9
10	Total Operating Expenses	174,547	170,870	180,784	10
11	Operating Income	17,225	18,760	24,242	11
	Total Other Income and Deductions				
12	Allowance for Equity Funds	98	1,606	591	12
13	Other - Net	(362)	(776)	(500)	13
14	Total Other Income and Deductions	(264)	830	91	14
15	Income Before Interest Expense	16,961	19,590	24,333	15
	Interest Expense				
16	Interest on Long Term-Debt	7,622	7,619	7,682	16
17	Other Interest Expense	330	106	147	17
18	Allowance for Borrowed Funds	(225)	(888)	(350)	18
19	Total Interest Expense	7,727	6,837	7,479	19
20	Net Income Available for Common Stock	$9,234	$12,753	$16,854	20
21	Earnings Per Share of Average Common Stock Outstandin (1)	N/A	N/A	N/A	21

(1) UNS Electric, Inc. is a subsidiary of UNS Energy Corporation and has no publicly traded stock; thus such information is not meaningful.

Supporting Schedules	Recap Schedules
(a) E-6	A-2
E-9	

UNS Electric, Inc.
Comparative Statements of Cash Flows
Test Year Ended December 31, 2014 and Prior Years Ended December 31, 2013 and 2012
(Thousands of Dollars)

Line No.	Description	2014	2013	2012	Line No.
	Cash Flows from Operating Activities				
1	Net Income	$9,234	$12,753	$16,854	1
2	Depreciation & Amortization Expense	21.878	19,648	18.869	2
3	Amortizatization of deferred debt issue costs	182	182	182	3
4	Use of REC's for Compliance	2,612	1,716	864	4
5	Deferred Income Tax	6,069	13,259	3.445	5
6	Pension and Postretirement Expense	891	1,239	1,075	6
7	Pension and Postretirement Funding	(810)	(865)	(1,552)	7
8	Increase (Decrease) to Reflect PPFAC Recovery	3,650	(1,871)	(958)	8
9	Fortis-Merger Customer Credits	4,266	0	0	9
10	LFCR Revenue	(1,378)	(900)	0	10
11	Allowance for Equity Funds Used Duming Construction	(98)	(1,606)	(591)	11
	Changes in Current Assets and Liabilities				
12	Accounts Payable and Accured Charges	1,328	675	1,106	12
13	Material and Fuel Inventory	(494)	(545)	(1,190)	13
14	Accounts Receivable	(2,399)	(1,703)	183	14
15	Tax Other Than Income Taxes	90	408	80	15
16	Regulatory Assets	310	0	821	16
17	Regulatory Liability	815	7,441	2,327	17
18	Other	(2,673)	(6,518)	8,022	18
19	Net Cash Flow from Operations Activities	43,468	43,313	49,537	19
	Cash Flows From Investing Activities				
20	Purchase of Renewable Energy Credits	(4,066)	(3,948)	(1.868)	20
21	Capital Expenditures	(93,270)	(56,278)	(38,554)	21
22	Other Cash Payments	346	933	3,827	22
23	Net Cash Flows from Investing Activities	(96,990)	(59,293)	(36,595)	23
	Cash Flows from Financing Activities				
24	Proceeds from Borrowings under Revolver	57,000	35,000	0	24
25	Equity Investment in UNS Electric	45,000	0	0	25
26	Repayment of Borrowings under Revolver	(39,000)	(13,000)	0	26
27	Dividend Payment	(10,000)	(10,000)	(10,000)	27
28	Other Cash Payments	1,117	939	188	28
29	Net Cash Flows from Financing Activities	54,117	12,939	(9,812)	29
30	Net Increase (Decrease) in Cash and Cash Equivalents	595	(3,041)	3,130	30
31	Cash and Cash Equivalents, Beginning of Period	5.012	8,053	4,923	31
32	Cash and Cash Equivalents, End of Period	$5,607	$5,012	$8,053	32

Supporting Schedules	Recap Schedules
N/A	A-5

UNS Electric, Inc.
Comparative Statements of Changes in Stockholders' Equity (Deficit)
Test Year Ended December 31, 2014 and Prior Years Ended December 31, 2013 and 2012
(Thousands of Dollars, except shares outstanding)

Description	Common Stock Shares Outstanding	Common Stock Amount	Premium on Common Stock	Common Stock Expense	Accumulated Earnings or (Deficit)	Comprehensive Income	Total Common Stock Equity or (Deficit)	Line No.
Balance, December 31, 2011	1,000	$78,887	$0	$0	$57,278	($38)	$136,127	1
Net Income for Year					16,854		16,854	2
Dividend Declared					(10,000)		(10,000)	3
Equity in Earnings					0		0	4
Minimum Pension Liability Adjustment						0	0	5
Equity Contribution from UniSource Energy Services		0					0	6
Other	0	0				(220)	(220)	7
Balance, December 31, 2012	1,000	78,887	0	0	64,132	(258)	142,761	8
Net Income for Year					12,753		12,753	9
Dividend Declared					(10,000)		(10,000)	10
Equity in Earnings					0		0	11
Minimum Pension Liability Adjustment							0	12
Equity Contribution from UniSource Energy Services		0					0	13
Other	0	0				87	87	14
Balance, December 31, 2013	1,000	78,887	0	0	66,885	(171)	145,601	15
Net Income for Year					9,234		9,234	16
Dividend Declared					(10,000)		(10,000)	17
Equity in Earnings							0	18
Pension Plan Measurement Date Change (FAS 158)					0		0	19
Minimum Pension Liability Adjustment							0	20
Equity Contribution from UniSource Energy Services		45,000					45,000	21
Other						97	97	22
Balance, December 31, 2014	1,000	$123,887	$0	$0	$66,119	($74)	$189,932	23

Supporting Schedules
N/A

Recap Schedules
N/A

UNS Electric, Inc.
Detail of Electric Utility Plant - Summary Statement
Test Year Ended December 31, 2014

Line No.	Description	2014 (a)	Net Additions (a)	2013 (a)	Line No.
	Utility Plant in Service				
1	Intangible Plant	$7,710	($169)	$7,879	1
2	Other Production Plant	194,876	99,569	95,307	2
3	Transmission Plant	120,585	5,488	115,097	3
4	Distribution Plant	421,136	20,643	400,493	4
5	General Plant	41,845	5,542	36,303	5
6	Gross Plant in Service	786,152	131,073	655,079	6
7	Construction Work in Progress	6,116	(14,591)	20,707	7
8	Plant Held for Future Use	891	0	891	8
9	Utility Plant Under Capital Leases	0	0	0	9
10	Acquisition Discount	(115,671)	(12,890)	(102,781)	10
11	Total Utility Plant	677,488	103,592	573,896	11
12	Accumulated Depreciation and Amortization	(323,817)	(37,011)	(286,806)	12
13	Accumulated Amortization - Capital Leases	0	0	0	13
14	Accumulated Amort. - Acquisition Discount	44,797	3,664	41,133	14
15	Total Accumulated Depreciation and Amortization	(279,020)	(33,347)	(245,673)	15
16	Total Net Utility Plant in Service	$398,468	$70,245	$328,223	16

Supporting Schedules
(a) E-5 (P2-4)

Recap Schedules
E-1

UNS Electric, Inc.
Detail of Electric Utility Plant
Test Year Ended December 31, 2014

Line No.	Acct. No.	Description	2014	Net Additions	2013	Line No.
		Utility Plant In Service				
		Intangible Plant				
1	302	Franchises & Consents	$0	$0	$0	1
2	303	Miscellaneous Intangible Plant	7,710	(169)	7,879	2
3		Total Intangible Plant	7,710	(169)	7,879	3
		Other Production Plant				
4	340	Land & Rights	268	56	212	4
5	341	Structures & Improvements	7,452	2,854	4,598	5
6	342	Fuel Holders, Producers, & Accessories	3,473	2,260	1,213	6
7	343	Prime Movers	76,022	62,548	13,474	7
8	344	Generators	76,792	26,647	50,145	8
9	345	Accessory Electric Equipment	14,722	2,610	12,112	9
10	346	Misc. Power Plant Equipment	14,984	2,271	12,713	10
11	347	ARO Other Production	1,163	323	840	11
12		Total Other Production Plant	194,876	99,569	95,307	12
		Transmission Plant				
13	350	Land & Rights	11,723	(260)	11,983	13
14	352	Structures & Improvements	1,224	306	918	14
15	353	Station Equipment	36,989	801	36,188	15
16	354	Towers & Fixtures	86	0	86	16
17	355	Poles & Fixtures	48,252	(432)	48,684	17
18	356	Overhead Conductors & Devices	22,048	5,073	16,975	18
19	358	Underground Conductors & Devices	30	0	30	19
20	359	Roads & Trails	233	0	233	20
21		Total Transmission Plant	120,585	5,488	115,097	21
		Distribution Plant				
22	360	Land & Rights	1,423	37	1,386	22
23	361	Structures & Improvements	7,508	814	6,694	23
24	362	Station Equipment	66,974	9,530	57,444	24
25	364	Poles, Towers, & Fixtures	95,105	1,859	93,246	25
26	365	Overhead Conductors & Devices	75,803	4,284	71,519	26
27	366	Underground Conduit	22,283	1,587	20,696	27
28	367	Underground Conductors & Devices	44,071	464	43,607	28
29	368	Line Transformers	75,194	1,471	73,723	29
30	369	Services	17,634	502	17,132	30
31	370	Meters	10,075	(51)	10,126	31
32	373	Street Lights and Signal Systems	5,066	146	4,920	32
33		Total Distribution Plant	421,136	20,643	400,493	33

Supporting Schedules
N/A

Recap Schedules
E-5 (P1)

UNS Electric, Inc.
Detail of Electric Utility Plant
Test Year Ended December 31, 2014

Line No.	Acct. No.	Description	2014	Net Additions	2013	Line No.
		General Plant				
34	389	Land & Rights	758	0	758	34
35	390	Structures & Improvements	5,835	749	5,086	35
36	391	Office Furniture & Equipment	3,132	229	2,903	36
37	392	Transportation Equipment	14,481	800	13,681	37
38	393	Stores Equipment	358	10	348	38
39	394	Tools, Shop, & Garage Equipment	2,703	78	2,625	39
40	395	Laboratory Equipment	1,937	4	1,933	40
41	396	Power Operated Equipment	4,460	1,424	3,036	41
42	397	Communication Equipment	8,022	2,216	5,806	42
43	398	Miscellaneous Equipment	159	32	127	43
44		Total General Plant	41,845	5,542	36,303	44
45		Total Electric Plant in Service	$786,152	$131,073	$655,079	45

Supporting Schedules
N/A

Recap Schedules
E-5 (P1)

UNS Electric, Inc.
Detail of Electric Utility Plant
Test Year Ended December 31, 2014
(Thousands of Dollars)

Line No.	Acct. No.	Description	2014	Net Additions	2013	Line No.
		Acquisition Discount				
		Intangible Plant				
1	302	Franchises & Consents	$0	$0	$0	1
2	303	Miscellaneous Intangible Plant	(2,181)	(3)	(2,178)	2
3		Total Intangible Plant	(2,181)	(3)	(2,178)	3
		Other Production Plant				
4	340	Land & Rights	(430)	(8)	(422)	4
5	341	Structures & Improvements	(564)	(414)	(150)	5
6	342	Fuel Holders, Producers, & Accessories	(632)	(330)	(302)	6
7	343	Prime Movers	(12,794)	(9,194)	(3,600)	7
8	344	Generators	(2,750)	(1,597)	(1,153)	8
9	345	Accessory Electric Equipment	(1,169)	(440)	(729)	9
10	346	Misc. Power Plant Equipment	(576)	(331)	(245)	10
11		Total Other Production Plant	(18,915)	(12,314)	(6,601)	11
		Transmission Plant				
12	350	Land & Rights	(704)	0	(704)	12
13	352	Structures & Improvements	(41)	(7)	(34)	13
14	353	Station Equipment	(6,381)	(469)	(5,912)	14
15	354	Towers & Fixtures	(236)	0	(236)	15
16	355	Poles & Fixtures	(3,190)	0	(3,190)	16
17	356	Overhead Conductors & Devices	(3,718)	0	(3,718)	17
18	358	Underground Conductors & Devices	0	0	0	18
19	359	Roads & Trails	(66)	0	(66)	19
20		Total Transmission Plant	(14,336)	(476)	(13,860)	20
		Distribution Plant				
21	360	Land & Rights	(643)	0	(643)	21
22	361	Structures & Improvements	(1,562)	0	(1,562)	22
23	362	Station Equipment	(9,649)	0	(9,649)	23
24	364	Poles, Towers, & Fixtures	(22,656)	0	(22,656)	24
25	365	Overhead Conductors & Devices	(13,519)	0	(13,519)	25
26	366	Underground Conduit	(4,511)	0	(4,511)	26
27	367	Underground Conductors & Devices	(5,562)	0	(5,562)	27
28	368	Line Transformers	(10,742)	0	(10,742)	28
29	369	Services	(4,012)	0	(4,012)	29
30	370	Meters	(3,060)	0	(3,060)	30
31	373	Street Lights and Signal Systems	(1,199)	0	(1,199)	31
32		Total Distribution Plant	(77,115)	0	(77,115)	32

Supporting Schedules
N/A

Recap Schedules
E-5 (P1)

UNS Electric, Inc.
Detail of Electric Utility Plant
Test Year Ended December 31, 2015

Line No.	Acct. No.	Description	June 30, 2012	Net Additions	December 31, 2011	Line No.
		Acquisition Discount				
		General Plant			0	
33	389	Land & Rights	(32)	0	(32)	33
34	390	Structures & Improvements	(728)	(94)	(634)	34
35	391	Office Furniture & Equipment	(461)	0	(461)	35
36	392	Transportation Equipment	(2)	(2)	0	36
37	393	Stores Equipment	(42)	(1)	(41)	37
38	394	Tools, Shop, & Garage Equipment	(859)	0	(859)	38
39	395	Laboratory Equipment	(362)	0	(362)	39
40	396	Power Operated Equipment	(172)	0	(172)	40
41	397	Communication Equipment	(444)	0	(444)	41
42	398	Miscellaneous Equipment	(22)	0	(22)	42
43		Total General Plant	(3,124)	(97)	(3,027)	43
44		Total Electric Plant in Service	($115,671)	($12,890)	($102,781)	44

Supporting Schedules
N/A

Recap Schedules
E-5 (P1)

UNS Electric, Inc.
Comparative Departmental Operating Income Statements
Test Year Ended December 31, 2014 and Prior Years Ended December 31, 2013 and 2012
(Thousands of Dollars)

Line No.	Description	2014	2013	2012	Line No.
	Operating Revenues				
1	Electric Retail Revenues				1
2	Residential	$83,981	$81,153	$77,294	2
3	Commercial	62,320	58,571	57,053	3
4	Industrial	21,408	20,653	25,521	4
5	Public Street & Highway Lighting	290	274	239	5
6	Total Retail Revenues	167,999	160,651	160,107	6
7	Sales for Resale	12,285	18,627	31,801	7
8	Other Operating Revenue	11,488	10,352	13,118	8
9	Total Operating Revenues	191,772	189,630	205,026	9
	Operating Expenses				
10	Fuel, Purchased Power & Transmission	107,290	108,000	116,139	10
11	Other Operations and Maintenance Expense	32,004	30,158	29,576	11
12	Depreciation and Amortization	22,847	20,345	19,530	12
13	Taxes Other than Income Taxes	5,940	5,898	4,727	13
14	Income Taxes	6,466	6,469	10,812	14
15	Total Operating Expenses	174,547	170,870	180,784	15
16	Operating Income	$17,225	$18,760	$24,242	16

Supporting Schedules
N/A

Recap Schedules
E-2

UNS Electric, Inc.
Electric Operating Statistics
Test Year Ended December 31, 2014 and Prior Years Ended December 31, 2013 and 2012

Line No.	Description	2014	2013	2012	Line No.
	kWh Sales				
1	Residential	815,235,844	843,616,737	835,783,925	1
2	Commercial	609,945,358	607,529,485	614,169,444	2
3	Industrial & Mining	249,444,202	246,253,190	303,927,538	3
4	Public Street & Highway Lighting	2,820,013	1,907,675	1,660,494	4
5	Total	1,677,445,417	1,699,307,087	1,755,541,401	5
	Average Number of Customers				
6	Residential	82,268	81,399	80,865	6
7	Commercial	10,113	10,576	10,459	7
8	Industrial & Mining	18	20	23	8
9	Public Street & Highway Lighting	2,388	552	474	9
10	Total	94,787	92,547	91,821	10
	Average Annual kWh Use				
11	Residential	9,909	10,364	10,336	11
12	Commercial	60,311	57,444	58,722	12
13	Industrial & Mining	13,794,149	12,312,660	13,214,241	13
14	Public Street & Highway Lighting	1,181	3,456	3,503	14
15	Total	17,697	18,362	19,119	15
16	Average Annual Revenue per Residential Customer	$1,037	$1,011	$970	16
	Direct Production Expenses				
17	Per Retail and Wholesale kWh Sold (cents) (Expenses are primarily purchased power)	4.99	4.41	4.35	17
	Direct Transmission Expenses				
18	Per Retail and Wholesale kWh Sold (cents) (Expenses are primarily transmission of electricity by others)	0.63	0.61	0.54	18

Supporting Schedules
N/A

Recap Schedules
N/A

UNS Electric, Inc.
Taxes Charged to Operations
Test Year Ended December 31, 2014 and Prior Years Ended December 31, 2013 and 2012
(Thousands of Dollars)

Line No.	Description	2014	2013	2012	Line No.
	Federal Taxes				
1	Income	$593	($5,914)	$5,417	1
2	Unemployment	4	5	5	2
3	FICA	349	439	411	3
4	Deferred Income Taxes	4,831	11,238	3,497	4
5	Total	5,777	5,768	9,330	5
	State Taxes				
6	Income	165	(917)	1,873	6
7	Unemployment	2	1	8	7
8	Deferred Income Taxes	877	2,062	25	8
9	Total	1,044	1,146	1,906	9
	Local Taxes				
10	Real and Personal Property	5,481	5,201	4,484	10
11	Other	104	252	(181)	11
12	Total	5,585	5,453	4,303	12
13	Total Taxes Charged to Operating Expenses	$12,406	$12,367	$15,539	13

Note: Taxes and assessments related to sales of energy are not included in revenues or other tax expense categories.

Supporting Schedules	Recap Schedules
N/A	E-2

UNS Electric, Inc.
Test Year Ended December 31, 2014
Notes to Financial Statements

See the attached FERC Form 1 December 31, 2014 and the FERC Form 1 as of December 31, 2012.

Supporting Schedules	Recap Schedules
N/A	N/A

Schedule

"F"

UNS Electric, Inc.
Income Statement - Test Year Ended December 31, 2014 and
Projected Year Ended December 31, 2015 at Present and Proposed Rates
(Thousands of Dollars Except Return on Average Common Equity)

Line No.	Description		Test Year Ended December 31, 2014 (a)	Projected Year Ended December 31, 2015 Present Rates	Projected Year Ended December 31, 2015 Proposed Rates	Line No.
1	Operating Revenues		$191,772	$190,675	$203,406	1
	Operating Expenses					
2	Fuel, Purchased Power & Transmission		107,290	108,103	98,212	2
3	Other Operations and Maintenance Expense		32,004	26,730	29,951	3
4	Depreciation and Amortization		22,847	24,192	18,052	4
5	Taxes Other than Income Taxes		5,940	7,645	7,645	5
6	Income Taxes		6,466	6,556	14,118	6
7	Other Amortization Expense		0	(1,572)	1,766	7
8	Total Operating Expenses		174,547	171,654	169,744	8
9	Operating Income		17,225	19,021	33,662	9
	Total Other Income and Deductions					
10	Allowance for Equity Funds		98	0	0	10
11	Other - Net		(362)	(478)	(478)	11
12	Total Other Income and Deductions		(264)	(478)	(478)	12
13	Income Before Interest Expense		16,961	18,543	33,184	13
	Interest Expense					
14	Interest on Long-Term Debt		7,622	8,441	8,441	14
15	Interest on Short-Term Debt		0	151	151	15
16	Other Interest Expense		330	(2,522)	291	16
17	Allowance for Borrowed Funds		(225)	(120)	(120)	17
18	Total Interest Expense		7,727	5,950	8,763	18
19	Net Income Available for Common Stock		$9,234	$12,593	$24,421	19
20	Earnings Per Share of Average Common Stock Outstanding	(1)	N/A	N/A	N/A	20
21	Return on Average Common Equity		5.50%	6.54%	12.31%	21

(1) UNS Electric, Inc. is a subsidiary of UNS Energy Corporation and has no publicly traded stock; thus such information is not meaningful.

Note: The statements above do not reflect ratemaking adjustments or jurisdictional allocations.

Supporting Schedules
(a) E-2

Recap Schedules
A-2

UNS Electric, Inc.
Statement of Cash Flows - Test Year Ended December 31, 2014 and
Projected Year Ended December 31, 2015 at Present and Proposed Rates
(Thousands of Dollars)

Line No.	Description	Test Year Ended December 31, 2014 (a)	Projected Year Ended December 31, 2015 Present Rates	Projected Year Ended December 31, 2015 Proposed Rates	Line No.
	Cash Flows from Operating Activities				
1	Net Income	$9,234	$15,140	$26,968	1
2	Depreciation and Amortization	22,060	23,552	17,412	2
3	Change in Collection of PPFAC Recoveries	0	0	(9,890)	3
4	Changes in LT regulatory Assets and Liabilities	(55)	994	(9,021)	4
5	Changes in Current Assets and Liabilities	(1,184)	(1,665)	(3,588)	5
6	Deferred Income Taxes	6,069	4,989	4,989	6
7	Pension Expense	81	(591)	(591)	7
8	Share Based Compensation Expense	575	560	560	8
9	AFUDC	(98)	0	0	9
10	LFCR	(1,378)	(289)	(289)	10
11	Other Cash Payments	8,164	4,954	4,954	11
12	Net Cash Flows from Operating Activities	43,468	47,644	31,504	12
	Cash Flows from Investing Activities				
13	Capital Expenditures	(93,270)	(37,685)	(37,685)	13
14	Other Payments for Investing Activities	(3,720)	(4,725)	(4,725)	14
15	Net Cash Flows from Investing Activities	(96,990)	(42,410)	(42,410)	15
	Cash Flow from Financing Activities				
16	Proceeds from Issuance of Long-Term Debt	0	130,000	130,000	16
17	Equity Investment in UNS Electric	45,000	0	0	17
18	Long Term Debt Retirements	0	(80,000)	(80,000)	18
19	Change in Short-Term Debt	0	(40,000)	(23,860)	19
20	Common Dividends Paid	(10,000)	(10,000)	(10,000)	20
21	Other Payments for Financing Activities	19,117	(1,300)	(1,300)	21
22	Net Cash Flows from Financing Activities	54,117	(1,300)	14,840	22
23	Net Increase (Decrease) in Cash	$595	$3,934	$3,934	23

Supporting Schedule
(a) E-3

Recap Schedules
A-5

UNS Electric, Inc.
Projected Construction Requirements
Test Year Ended December 31, 2014 and Projected Years 2015 through 2017 as of December 31
(Thousands of Dollars)

Line No.	Description	Test Year Ended December 31, 2014 (a), (b)	Projected Year Ended December 31, 2015 (a), (b)	2016 (a)	2017 (a)	Total 2015-2017	Line No.
1	Production Plant	$61,657	$11,132	$8,331	$7,126	$26,589	1
2	Transmission Plant	15,855	5,393	3,063	6,262	14,718	2
3	Distribution Plant	10,299	16,516	19,114	19,745	55,375	3
4	General Plant	5,234	4,524	5,577	5,514	15,615	4
5	Construction Expenditures	93,045	37,565	36,085	38,647	112,297	5
6	Capitalized Interest	225	120	522	509	1,151	6
7	Gross Construction Expenditures	93,270	37,685	36,607	39,156	113,448	7
8	Contributions in Aid of Construction	346	2,776	0	0	2,776	8
9	Net Construction Expenditures	$93,616	$40,461	$36,607	$39,156	$116,224	9

Supporting Schedules
N/A

Recap Schedules
(a) A-4
(b) F-2

UNS Electric, Inc.
Key Assumptions Used in Preparing Forecasts

Customer Growth and Sales
Retail customer growth is forecasted to be 0.59% for year ended December 31, 2015.
Retail sales growth is forecasted to be negative (3.5)% for the year ending December 31, 2015

Purchased Gas Costs
Natural gas costs are forecasted using forward market projections and completed hedging transactions as of January 19, 2015.

Energy Pricing for Purchases and Wholesale Sales
Energy Pricing for Purchases and Wholesale Sales is based on forward market projections as of January 19, 2015

Operations and Maintenance Expenses
O&M Expenses for 2015 are based on final budget as of December 2014.

Projected Construction Requirements Schedule F3
Construction expenditures for 2015 - 2017 are based on forecast as of December 2014.

Interest Rate Assumptions
The interest rate on temporary investments is forecasted at 0.127% in 2015.
The interest rate on short-term borrowings is forecasted at 1.391% in 2015.

Schedule

"G"

SCHEDULE G-1
SHEET 1 OF 1

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - SUMMARY AT PRESENT RATES
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	DESCRIPTION	TOTAL (A)	RESIDENTIAL SERVICE (B)	SMALL GENERAL SERVICE (C)	MEDIUM/ LARGE GENERAL SERVICE (E)	LARGE POWER SERVICE (G)	LIGHTING (H)
1	DEVELOPMENT OF RATE BASE						
2	Electric Plant In Service	$569,545,363	$355,060,733	$54,862,175	$146,410,407	$7,997,295	$5,214,752
3	Depreciation & Amort. Reserve	260,863,085	166,228,675	22,396,618	66,848,412	1,868,317	3,521,063
4	Net Plant In Service	$308,682,277	$188,832,058	$32,465,557	$79,561,995	$6,128,978	$1,693,689
5	ADDITIONS & DEDUCTIONS						
6	Cash Working Capital	($5,198,426)	($3,240,755)	($500,745)	($1,336,336)	($72,994)	($47,597)
7	Fuel Inventory	276,430	167,165	23,780	73,336	11,700	450
8	Materials & Supplies	11,353,152	7,077,677	1,093,607	2,918,503	159,416	103,949
9	Prepayments	743,554	463,540	71,624	191,142	10,441	6,808
10	Customer Advances for Construction	(3,833,219)	(2,446,421)	(378,008)	(1,008,789)	0	0
11	Customer Deposits	(4,427,886)	(2,188,260)	(1,933,430)	(306,196)	0	0
12	Deferred Credits - Asset Retirement	(421,645)	(262,858)	(40,615)	(108,390)	(5,921)	(3,861)
13	Plant Held for Future Use	0	0	0	0	0	0
14	Regulatory Assets	0	0	0	0	0	0
15	Accum Deferred Income Taxes	(35,161,108)	(21,919,815)	(3,386,938)	(9,038,704)	(493,716)	(321,935)
16	Total Additions & Deductions	($36,669,148)	($22,349,727)	($5,050,726)	($8,615,436)	($391,075)	($262,185)
17	TOTAL RATE BASE	$272,013,129	$166,482,331	$27,414,831	$70,946,559	$5,737,904	$1,431,504
18	DEVELOPMENT OF RETURN						
19	REVENUES FROM ELECTRIC SALES						
20	Base Revenues Present Rates	$147,176,645	73,653,026	11,905,151	53,699,953	7,375,505	543,010
21	Revenue Adjustments						
22	TOTAL ELECTRIC REVENUE FROM SALES	$147,176,645	$73,653,026	$11,905,151	$53,699,953	$7,375,505	$543,010
23	OTHER OPERATING REVENUES						
24	Miscellaneous Service Revenue	$1,386,204	$1,100,159	$172,379	$113,665	$0	$0
25	OTHER REVENUE	442,874	212,523	39,018	167,822	20,294	3,217
26	TOTAL OTHER OPERATING REVENUE	$1,829,078	$1,312,682	$211,397	$281,487	$20,294	$3,217
27	TOTAL OPERATING REVENUE	$149,005,723	$74,965,709	$12,116,548	$53,981,440	$7,395,800	$546,226
28	OPERATING EXPENSES						
29	Operation & Maintenance	$120,384,494	$67,436,536	$10,160,378	$37,045,703	$5,427,977	$313,899
30	Depreciation & Amortization	13,059,523	8,029,429	1,297,813	3,377,283	254,484	100,515
31	Interest on Customer Deposits	7,440	3,677	3,249	514	0	0
32	Taxes Other Than Income	6,149,421	3,843,749	597,937	1,576,340	71,007	60,388
33	Tax Expense	1,291,053	804,856	124,362	331,885	18,128	11,821
34	TOTAL OPERATING EXPENSES	$140,891,931	$80,118,247	$12,183,739	$42,331,725	$5,771,597	$486,623
35	OPERATING INCOME	$8,113,792	($5,152,538)	($67,191)	$11,649,716	$1,624,202	$59,604
36	RATE OF RETURN ON RATE BASE[1]	2.98%	-3.09%	-0.25%	16.42%	28.31%	4.16%
37	(ORIGINAL COST RATE BASE)						
38	OPERATING INCOME EXCLUDES OTHER OPERATING REVENUE	$6,284,715	($6,465,221)	($278,588)	$11,368,228	$1,603,908	$56,387
39	RATE OF RETURN	2.31%	-3.88%	-1.02%	16.02%	27.95%	3.94%
40	INPUTS						
41	TEST YEAR ADJUSTED SALES (kWh)	1,600,809,167	823,953,185	118,683,796	562,579,661	92,765,274	2,827,250
42	TEST YEAR ADJUSTED MARGIN REVENUES	$69,654,260	33,425,187	6,136,594	26,394,695	3,191,840	505,944
43	TEST YEAR ADJUSTED FUEL REVENUES	$77,522,386	40,227,839	5,768,557	27,305,258	4,183,666	37,065
44	TEST YEAR ADJUSTED CUSTOMERS	95,144	82,607	8,758	1,387	4	2,388

Note:
[1] Test Year Billed Margin Revenues calculated $69,916 more than Booked Revenues and therefore the calculated rate of return in Schedule G will be slightly different than Schedule A1

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - SUMMARY AT PROPOSED RATES
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	DESCRIPTION	TOTAL (A)	RESIDENTIAL SERVICE (B)	SMALL GENERAL SERVICE (C)	MEDIUM/ LARGE GENERAL SERVICE (E)	LARGE POWER SERVICE (G)	LIGHTING (H)
1	DEVELOPMENT OF RATE BASE						
2	Electric Plant in Service	$569,545,363	$355,060,733	$54,862,175	$146,410,407	$7,997,295	$5,214,752
3	Depreciation & Amort. Reserve	260,863,085	166,228,675	22,396,618	66,848,412	1,868,317	3,521,063
4	Net Plant in Service	$308,682,277	$188,832,058	$32,465,557	$79,561,995	$6,128,978	$1,693,689
5	ADDITIONS & DEDUCTIONS						
6	Cash Working Capital	($5,198,426)	($3,240,755)	($500,745)	($1,336,336)	($72,994)	($47,597)
7	Fuel Inventory	276,430	167,165	23,780	73,336	11,700	450
8	Materials & Supplies	11,353,152	7,077,677	1,093,607	2,918,503	159,416	103,949
9	Prepayments	743,554	463,540	71,624	191,142	10,441	6,808
10	Customer Advances for Construction	(3,833,219)	(2,446,421)	(378,008)	(1,008,789)	0	0
11	Customer Deposits	(4,427,886)	(2,188,260)	(1,933,430)	(306,196)	0	0
12	Deferred Credits - Asset Retirement	(421,645)	(262,858)	(40,615)	(108,390)	(5,921)	(3,861)
13	Plant Held for Future Use	0	0	0	0	0	0
14	Regulatory Assets	0	0	0	0	0	0
15	Accum Deferred Income Taxes	(35,161,108)	(21,919,815)	(3,386,938)	(9,038,704)	(493,716)	(321,935)
16	Total Additions & Deductions	($36,669,148)	($22,349,727)	($5,050,726)	($8,615,436)	($391,075)	($262,185)
17	TOTAL RATE BASE	$272,013,129	$166,482,331	$27,414,831	$70,946,559	$5,737,904	$1,431,504
18	CLAIMED RATE OF RETURN	7.67%	7.67%	7.67%	7.67%	7.67%	7.67%
19	RETURN ON RATE BASE	$20,852,600	$12,762,580	$2,101,628	$5,438,782	$439,869	$109,739
20	PROPOSED SALES REVENUE	$169,727,738	94,209,675	14,569,488	53,726,298	6,603,676	618,601
21	OTHER OPERATING REVENUES						
22	Miscellaneous Service Revenue	$1,386,204	$1,100,159	$172,379	$113,665	$0	$0
23	Other Revenue	442,874	212,523	39,018	167,822	20,294	3,217
24	TOTAL OTHER OPERATING REVENUE	$1,829,078	$1,312,682	$211,397	$281,487	$20,294	$3,217
25	TOTAL OPERATING REVENUE	$171,556,815	$95,522,357	$14,780,884	$54,007,786	$6,623,970	$621,818
26	OPERATING EXPENSES						
27	Operation & Maintenance	$120,384,494	$67,436,536	$10,160,378	$37,045,703	$5,427,977	$313,899
28	Depreciation & Amortization	13,059,523	8,029,429	1,297,813	3,377,283	254,484	100,515
29	Interest on Customer Deposits	7,440	3,677	3,249	514	0	0
30	Taxes Other Than Income	6,149,421	3,843,749	597,937	1,576,340	71,007	60,388
31	Tax Expense	8,556,716	4,910,258	755,183	2,529,822	330,280	31,173
32	TOTAL OPERATING EXPENSES	$148,157,593	$84,223,648	$12,814,560	$44,529,662	$6,083,749	$505,974
33							
34	OPERATING INCOME	$23,399,222	$11,298,709	$1,966,325	$9,478,124	$540,221	$115,844
35	RATE OF RETURN ON RATE BASE	8.60%	6.79%	7.17%	13.36%	9.41%	8.09%
36	RETURN AT PROPOSED RATES	$21,570,144	$9,986,026	$1,754,928	$9,196,636	$519,927	$112,627
37	RETURN ON RATE BASE	7.93%	6.00%	6.40%	12.96%	9.06%	7.87%
38	INPUTS						
39	TEST YEAR ADJUSTED SALES (kWh)	1,600,809,167	823,953,185	118,683,796	562,579,661	92,765,274	2,827,250
40	TEST YEAR PROPOSED MARGIN REVENUES	$92,205,352	53,981,835	8,800,930	26,421,040	2,420,010	581,536
41	TEST YEAR PROPOSED FUEL REVENUES	$77,522,386	40,227,839	5,768,557	27,305,258	4,183,666	37,065
42	TEST YEAR ADJUSTED CUSTOMERS	95,144	82,607	8,758	1,387	4	2,388

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - RATE BASE ALLOCATION TO CLASSES OF SERVICES
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCOUNT	FERC ACCOUNT DESCRIPTION	Allocation	TOTAL UNSE	RESIDENTIAL	SMALL GENERAL SERVICE	MED./LRG. GENERAL SERVICE	LARGE POWER SERVICE	LIGHTING
1	301-303	Total Intangible Plant	PISXGENL	$7,646,054	$4,766,633	$736,516	$1,965,536	$107,362	$70,007
2		Total Steam Production							
3	310	Land & Land Rights	DPROD	$0	$0	$0	$0	$0	$0
4	311	Structures & Improvements	DPROD	0	0	0	0	0	0
5	312	Boiler Plant Equipment	DPROD	0	0	0	0	0	0
6	313	Engines & Engine-Driven Generators	DPROD	0	0	0	0	0	0
7	314	Turbogenerator Units	DPROD	0	0	0	0	0	0
8	315	Accessory Electric Equipment	DPROD	0	0	0	0	0	0
9	316	Miscellaneous Power Plant Equipment	DPROD	0	0	0	0	0	0
10	114	San Juan & Irvington Acquistion Adjustment	DPROD	0	0	0	0	0	0
11	102	Electric Plant Purchased or Sold	DPROD	0	0	0	0	0	0
12		Total Steam Production		$0	$0	$0	$0	$0	$0
13		Other Production Plant							
14	340	Land & Land Rights	DPROD	($125,742)	($76,040)	($10,817)	($33,359)	($5,322)	($205)
15	341	Structures & Improvements	DPROD	6,849,569	4,142,119	589,243	1,817,159	289,904	11,144
16	342	Fuel Holders, Producers, & Accessories	DPROD	2,826,837	1,709,465	243,182	749,947	119,644	4,599
17	343	Prime Movers	DPROD	62,410,318	37,741,207	5,368,930	16,557,166	2,641,478	101,537
18	344	Generators	DPROD	73,947,185	44,717,862	6,361,404	19,617,843	3,129,769	120,307
19	345	Accessory Electric Equipment	DPROD	13,563,682	8,202,325	1,166,834	3,598,382	574,074	22,067
20		Miscellaneous Power Plant Equipment	DPROD	14,388,420	8,701,067	1,237,783	3,817,181	608,981	23,409
21		Total Other Production Plant		$173,860,268	$105,138,005	$14,956,558	$46,124,319	$7,358,528	$282,858
22		Total Production Plant		$173,860,268	$105,138,005	$14,956,558	$46,124,319	$7,358,528	$282,858
23	350-359	Transmission	DTRAN	$0	$0	$0	$0	$0	$0
24	XXX	Intentionally Blank	DTRAN	0	0	0	0	0	0
25		Total Transmission Plant		$0	$0	$0	$0	$0	$0
26		Distribution Plant							
27	360	Land & Rights	DDISPSUB	$837,790	$535,835	$76,148	$224,398	$0	$1,409
28	361	Structures & Improvements	DDISPSUB	6,085,135	3,891,942	553,087	1,629,871	0	10,235
29	362	Station Equipment	DDISPSUB	58,174,288	37,207,217	5,287,544	15,581,677	0	97,850
30	364	Poles, Towers, & Fixtures	DDISPOLE	74,467,314	47,627,940	6,768,440	19,945,678	0	125,255
31	365	Overhead Conductors & Devices	DDISTCON	63,488,578	40,606,140	5,770,567	17,005,081	0	106,789
32	366	Underground Conduit	DDISTUCON	18,173,564	11,623,481	1,651,821	4,867,693	0	30,568
33	367	Underground Conductors & Devices	DDISTUDEV	39,003,990	24,946,243	3,545,128	10,447,013	0	65,605
34	368	Line Transformers	DDISTLINET	65,409,315	41,834,609	5,945,146	17,519,540	0	110,020
35	369	Services	CUST	13,979,252	12,449,691	1,319,922	209,035	603	0
36	370	Meters	CMETERS	7,287,096	1,267,806	4,671,929	1,338,326	9,035	0
37	373	Street Lighting & Signal Systems	DDISTLTG	3,973,928	0	0	0	0	3,973,928
38	374	Asset Retirement Obligation	DDISPSUB	0	0	0	0	0	0
39		Total Distribution Plant		$350,880,250	$221,990,904	$35,589,734	$88,768,313	$9,638	$4,521,661

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - RATE BASE ALLOCATION TO CLASSES OF SERVICES
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCOUNT	FERC ACCOUNT DESCRIPTION	Allocation	TOTAL UNSE	RESIDENTIAL	SMALL GENERAL SERVICE	MED./LRG. GENERAL SERVICE	LARGE POWER SERVICE	LIGHTING
		TOTAL PLANT IN SERVICE EXCLUDING INTANGIBLE & GENERAL PLANT							
1									
2				$524,740,517	$327,128,909	$50,546,292	$134,892,632	$7,368,166	$4,804,519
3	389-398	Total General Plant	PISXGENL	$37,158,791	$23,165,192	$3,579,367	$9,552,239	$521,767	$340,226
4									
5		TOTAL ELECTRIC PLANT IN SERVICE							
6				$569,545,363	$355,060,733	$54,862,175	$146,410,407	$7,997,295	$5,214,752
7		Less: Accumulated Depreciation							
8		Total Intangible Plant AD	PISXGENL	$2,493,520	$1,554,487	$240,191	$640,998	$35,013	$22,831
9		Production Plant		$0	$0	$0	$0	$0	$0
10		Other Production Plant		37,652,975	22,769,772	3,239,147	9,989,159	1,593,639	61,259
11		Total Production Plant AD	DPROD	$37,652,975	$22,769,772	$3,239,147	$9,989,159	$1,593,639	$61,259
12		Transmission Non-EHV (138 KV & below) AD	DTNEHV	$0	$0	$0	$0	$0	$0
13		Transmission EHV (345 KV & above) AD	DTEHV	0	0	0	0	0	0
14		Total Transmission Plant		$0	$0	$0	$0	$0	$0
15		Distribution Plant AD							
16	360	Land & Rights	DDISPSUB	$58,400	$37,352	$5,308	$15,642	$0	$98
17	361	Structures & Improvements	PLT361	2,360,634	1,509,818	214,561	632,283	0	3,971
18	362	Station Equipment	PLT362	24,187,350	15,469,789	2,198,423	6,478,454	0	40,684
19	364	Poles, Towers, & Fixtures	PLT364	59,419,065	38,003,354	5,400,684	15,915,083	0	99,944
20	365	Overhead Conductors & Devices	PLT365	40,236,966	25,734,832	3,657,195	10,777,259	0	67,679
21	366	Underground Conduit	PLT366	8,289,171	5,301,603	753,415	2,220,211	0	13,943
22	367	Underground Conductors & Devices	PLT367	20,316,091	12,993,803	1,846,559	5,441,558	0	34,172
23	368	Line Transformers	PLT368	39,298,056	25,134,322	3,571,856	10,525,777	0	66,100
24	369	Services	PLT369	8,208,556	7,310,404	775,053	122,745	354	0
25	370	Meters	PLT370	(1,813,849)	(315,573)	(1,162,901)	(333,126)	(2,249)	0
26	373	Street Lighting & Signal Systems	PLT373	2,952,870	0	0	0	0	2,952,870
27	374	Asset Retirement Obligation	DDISPSUB	0	0	0	0	0	0
28		Total Distribution AD		$203,513,309	$131,179,705	$17,260,152	$51,795,887	($1,895)	$3,279,460
29		General Plant Accumulated Depreciation	GENLPIS	$17,203,281	$10,724,711	$1,657,128	$4,422,368	$241,561	$157,513
30		TOTAL ACCUMULATED DEPRECIATION		$260,863,085	$166,228,675	$22,396,618	$66,848,412	$1,868,317	$3,521,063

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - RATE BASE ALLOCATION TO CLASSES OF SERVICES
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCOUNT	FERC ACCOUNT DESCRIPTION	Allocation	TOTAL UNSE	RESIDENTIAL	SMALL GENERAL SERVICE	MED./LRG. GENERAL SERVICE	LARGE POWER SERVICE	LIGHTING
1		TOTAL NET PLANT IN SERVICE		$308,682,277	$188,832,058	$32,465,557	$79,561,995	$6,128,978	$1,693,689
2		Working Capital							
3	n/a	Cash Working Capital	OM	($5,198,426)	($3,240,755)	($500,745)	($1,336,336)	($72,994)	($47,597)
4	151, 152	Fuel Inventory	EPROD	276,430	167,165	23,780	73,336	11,700	450
5	154, 163	Materials & Supplies	OM	11,353,152	7,077,677	1,093,607	2,918,503	159,416	103,949
6	165	Prepayments	OM	743,554	463,540	71,624	191,142	10,441	6,808
7		Total Working Capital		$7,174,709	$4,467,627	$688,266	$1,846,645	$108,562	$63,610
8		Less: Customer Contributions							
9	252	Customer Advances for Construction	DCUSTADV	($3,833,219)	($2,446,421)	($378,008)	($1,008,789)	$0	$0
10	235	Customer Deposits	DCUSTDEP	(4,427,886)	(2,188,260)	(1,933,430)	(306,196)	0	0
11	230&253	Deferred Credits - Asset Retirement	TOTPIS	(421,645)	(262,858)	(40,615)	(108,390)	(5,921)	(3,861)
12		Total Less: Customer Contributions		($8,682,750)	($4,897,539)	($2,352,054)	($1,423,376)	($5,921)	($3,861)
13		Other Rate Base							
14	105.0	Plant Held for Future Use - Transmission Plant	DTNEHV	$0	$0	$0	$0	$0	$0
15	182.3	Regulatory Assets	DISTPIS	0	0	0	0	0	0
16	254	Regulatory Liabilities	DISTPIS	0	0	0	0	0	0
17		Total Other Rate Base		$0	$0	$0	$0	$0	$0
18		Less: Accumulated Deferred Taxes (ADIT)							
19	190	ADIT	TOTPIS	$15,091,263	$9,408,056	$1,453,685	$3,879,441	$211,905	$138,175
20	282	ADIT - Other Property	TOTPIS	(50,252,371)	(31,327,871)	(4,840,623)	(12,918,146)	(705,621)	(460,110)
21		Total Accumulated Deferred Taxes		($35,161,108)	($21,919,815)	($3,386,938)	($9,038,704)	($493,716)	($321,935)
22		TOTAL RATE BASE		$272,013,129	$166,482,331	$27,414,831	$70,946,559	$5,737,904	$1,431,504

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - RATE BASE ALLOCATION TO CLASSES OF SERVICES
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCOUNT	FERC ACCOUNT DESCRIPTION	Allocation	RESIDENTIAL STANDARD SERVICE DEMAND	RESIDENTIAL STANDARD SERVICE ENERGY	RESIDENTIAL STANDARD SERVICE CUSTOMER	SMALL GENERAL SERVICE DEMAND	SMALL GENERAL SERVICE ENERGY	SMALL GENERAL SERVICE CUSTOMER	MEDIUM/LARGE GENERAL DEMAND	MEDIUM/LARGE GENERAL ENERGY
1	301-303	Total Intangible Plant	PISXGENL	$3,280,935	$0	$1,485,698	$466,479	$0	$270,037	$1,404,513	$0
2		Total Steam Production									
3	310	Land & Land Rights	DPROD	$0	$0	$0	$0	$0	$0	$0	$0
4	311	Structures & Improvements	DPROD	0	0	0	0	0	0	0	0
5	312	Boiler Plant Equipment	DPROD	0	0	0	0	0	0	0	0
6	313	Engines & Engine-Driven Generators	DPROD	0	0	0	0	0	0	0	0
7	314	Turbogenerator Units	DPROD	0	0	0	0	0	0	0	0
8	315	Accessory Electric Equipment	DPROD	0	0	0	0	0	0	0	0
9	316	Miscellaneous Power Plant Equipment	DPROD	0	0	0	0	0	0	0	0
10	114	San Juan & Irvington Acquistion Adjustment	DPROD	0	0	0	0	0	0	0	0
11	102	Electric Plant Purchased or Sold	DPROD	0	0	0	0	0	0	0	0
12		Total Steam Production		$0	$0	$0	$0	$0	$0	$0	$0
13		Other Production Plant									
14	340	Land & Land Rights	DPROD	($76,040)	$0	$0	($10,817)	$0	$0	($33,359)	$0
15	341	Structures & Improvements	DPROD	4,142,119	0	0	589,243	0	0	1,817,159	0
16	342	Fuel Holders, Producers, & Accessories	DPROD	1,709,465	0	0	243,182	0	0	749,947	0
17	343	Prime Movers	DPROD	37,741,207	0	0	5,368,930	0	0	16,557,166	0
18	344	Generators	DPROD	44,717,862	0	0	6,361,404	0	0	19,617,843	0
19	345	Accessory Electric Equipment	DPROD	8,202,325	0	0	1,166,834	0	0	3,598,382	0
20		Miscellaneous Power Plant Equipment	DPROD	8,701,067	0	0	1,237,783	0	0	3,817,181	0
21		Total Other Production Plant		$105,138,005	$0	$0	$14,956,558	$0	$0	$46,124,319	$0
22		Total Production Plant		$105,138,005	$0	$0	$14,956,558	$0	$0	$46,124,319	$0
23	350-359	Transmission	DTRAN	$0	$0	$0	$0	$0	$0	$0	$0
24	XXX	Intentionally Blank	DTRAN	0	0	0	0	0	0	0	0
25		Total Transmission Plant		$0	$0	$0	$0	$0	$0	$0	$0
26		Distribution Plant									
27	360	Land & Rights	DDISPSUB	$535,835.02	$0.00	$0.00	$76,147.90	$0.00	$0.00	$224,397.54	$0.00
28	361	Structures & Improvements	DDISPSUB	$3,891,942	$0	$0	$553,087	$0	$0	$1;629,871	$0
29	362	Station Equipment	DDISPSUB	37,207,217	0	0	5,287,544	0	0	15,581,677	0
30	364	Poles, Towers, & Fixtures	DDISPOLE	19,051,176	0	28,576,764	2,707,376	0	4,061,064	7,978,271	0
31	365	Overhead Conductors & Devices	DDISTCON	26,393,991	0	14,212,149	3,750,869	0	2,019,699	11,053,303	0
32	366	Underground Conduit	DDISTUCON	0	0	11,623,481	0	0	1,651,821	0	0
33	367	Underground Conductors & Devices	DDISTUDEV	16,215,058	0	8,731,185	2,304,333	0	1,240,795	6,790,559	0
34	368	Line Transformers	DDISTLINET	16,733,843	0	25,100,765	2,378,058	0	3,567,088	7,007,816	0
35	369	Services	CUST	0	0	12,449,691	0	0	1,319,922	0	0
36	370	Meters	CMETERS	0	0	1,267,806	0	0	4,671,929	0	0
37	373	Street Lighting & Signal Systems	DDISTLTG	0	0	0	0	0	0	0	0
38	374	Asset Retirement Obligation	DDISPSUB	0	0	0	0	0	0	0	0
39		Total Distribution Plant		$120,029,063	$0	$101,961,841	$17,057,415	$0	$18,532,318	$50,265,894	$0

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - RATE BASE ALLOCATION TO CLASSES OF SERVICES
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCOUNT	FERC ACCOUNT DESCRIPTION	Allocation	RESIDENTIAL STANDARD SERVICE DEMAND	RESIDENTIAL STANDARD SERVICE ENERGY	RESIDENTIAL STANDARD SERVICE CUSTOMER	SMALL GENERAL SERVICE DEMAND	SMALL GENERAL SERVICE ENERGY	SMALL GENERAL SERVICE CUSTOMER	MEDIUM/LARGE GENERAL DEMAND	MEDIUM/LARGE GENERAL ENERGY
1		TOTAL PLANT IN SERVICE EXCLUDING INTANGIBLE & GENERAL PLANT									
2				$225,167,067	$0	$101,961,841	$32,013,974	$0	$18,532,318	$96,390,213	$0
3	389-398	Total General Plant	PISXGENL	$15,944,902	$0	$7,220,290	$2,267,026	$0	$1,312,341	$6,825,743	$0
4											
5		TOTAL ELECTRIC PLANT IN SERVICE									
6				$244,392,904	$0	$110,667,829	$34,747,479	$0	$20,114,696	$104,620,468	$0
7		Less: Accumulated Depreciation									
8		Total Intangible Plant AD	PISXGENL	$1,069,974	$0	$484,514	$152,128	$0	$88,064	$458,038	$0
9		Production Plant		$0	$0	$0	$0	$0	$0	$0	$0
10		Other Production Plant		$22,769,772	$0	$0	$3,239,147	$0	$0	$9,989,159	$0
11		Total Production Plant AD	DPROD	$22,769,772	$0	$0	$3,239,147	$0	$0	$9,989,159	$0
12		Transmission Non-EHV (138 KV & below) AD	DTNEHV	$0	$0	$0	$0	$0	$0	$0	$0
13		Transmission EHV (345 KV & above) AD	DTEHV	0	0	0	0	0	0	0	0
14		Total Transmission Plant		$0	$0	$0	$0	$0	$0	$0	$0
15		Distribution Plant AD									
16	360	Land & Rights	DDISPSUB	$37,351.85	$0.00	$0.00	$5,308.10	$0.00	$0.00	$15,642.25	$0.00
17	361	Structures & Improvements	PLT361	1,509,818	$0	$0	$214,561	$0	$0	$632,283	$0
18	362	Station Equipment	PLT362	15,469,789	$0	$0	$2,198,423	$0	$0	$6,478,454	$0
19	364	Poles, Towers, & Fixtures	PLT364	15,201,341	$0	$22,802,012	$2,160,273	$0	$3,240,410	$6,366,033	$0
20	365	Overhead Conductors & Devices	PLT365	16,727,641	$0	$9,007,191	$2,377,177	$0	$1,280,018	$7,005,219	$0
21	366	Underground Conduit	PLT366	0	$0	$5,301,603	$0	$0	$753,415	$0	$0
22	367	Underground Conductors & Devices	PLT367	8,445,972	$0	$4,547,831	$1,200,263	$0	$646,295	$3,537,013	$0
23	368	Line Transformers	PLT368	10,053,729	$0	15,080,593	1,428,743	0	2,143,114	4,210,311	0
24	369	Services	PLT369	0	0	7,310,404	0	0	775,053	0	0
25	370	Meters	PLT370	0	0	(315,573)	0	0	(1,162,901)	0	0
26	373	Street Lighting & Signal Systems	PLT373	0	0	0	0	0	0	0	0
27	374	Asset Retirement Obligation	DDISPSUB	0	0	0	0	0	0	0	0
28		Total Distribution AD		$67,445,642	$0	$63,734,062	$9,584,748	$0	$7,675,404	$28,244,955	$0
29		General Plant Accumulated Depreciation	GENLPIS	$7,381,958	$0	$3,342,754	$1,049,558	$0	$607,570	$3,160,091	$0
30		TOTAL ACCUMULATED DEPRECIATION		$98,667,346	$0	$67,561,329	$14,025,580	$0	$8,371,038	$41,852,243	$0

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - RATE BASE ALLOCATION TO CLASSES OF SERVICES
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCOUNT	FERC ACCOUNT DESCRIPTION	Allocation	RESIDENTIAL STANDARD SERVICE DEMAND	ENERGY	CUSTOMER	SMALL GENERAL SERVICE DEMAND	ENERGY	CUSTOMER	MEDIUM/LARGE GENERAL DEMAND	ENERGY
1		TOTAL NET PLANT IN SERVICE		$145,725,558	$0	$43,106,500	$20,721,899	$0	$11,743,658	$62,768,225	$0
2		Working Capital									
3	n/a	Cash Working Capital	OM	($2,230,654)	$0	($1,010,101)	($317,152)	$0	($183,593)	($954,905)	$0
4	151, 152	Fuel Inventory	EPROD	$167,165	$0	$0	$23,780	$0	$0	$73,336	$0
5	154, 163	Materials & Supplies	OM	$4,871,657	$0	$2,206,020	$692,646	$0	$400,960	$2,085,474	$0
6	165	Prepayments	OM	$319,060	$0	$144,479	$45,364	$0	$26,260	$136,584	$0
7		Total Working Capital		$3,127,228	$0	$1,340,398	$444,638	$0	$243,627	$1,340,489	$0
8		Less: Customer Contributions									
9	252	Customer Advances for Construction	DCUSTADV	($2,446,421)	$0	$0	($378,008)	$0	$0	($1,008,789)	$0
10	235	Customer Deposits	DCUSTDEP	($2,188,260)	$0	$0	($1,933,430)	$0	$0	($306,196)	$0
11	230&253	Deferred Credits - Asset Retirement	TOTPIS	(143,566)	0	(119,292)	(22,183)	0	(18,432)	(59,200)	0
12		Total Less: Customer Contributions		($4,778,247)	$0	($119,292)	($2,333,622)	$0	($18,432)	($1,374,186)	$0
13		Other Rate Base									
14	105.0	Plant Held for Future Use - Transmission Plant	DTNEHV	$0	$0	$0	$0	$0	$0	$0	$0
15	182.3	Regulatory Assets	DISTPIS	$0	$0	$0	$0	$0	$0	$0	$0
16	254	Regulatory Liabilities	DISTPIS	$0	$0	$0	$0	$0	$0	$0	$0
17		Total Other Rate Base		$0	$0	$0	$0	$0	$0	$0	$0
18		Less: Accumulated Deferred Taxes (ADIT)									
19	190	ADIT	TOTPIS	$6,475,687	$0	$2,932,369	$920,705	$0	$532,980	$2,772,132	$0
20	282	ADIT - Other Property	TOTPIS	($21,563,379)	$0	($9,764,491)	($3,065,854)	$0	($1,774,768)	($9,230,918)	$0
21		Total Accumulated Deferred Taxes		($15,087,692)	$0	($6,832,122)	($2,145,149)	$0	($1,241,789)	($6,458,786)	$0
22		TOTAL RATE BASE		$128,986,847	$0	$37,495,484	$16,687,767	$0	$10,727,064	$56,275,742	$0

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - RATE BASE ALLOCATION TO CLASSES OF SERVICES
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCOUNT	FERC ACCOUNT DESCRIPTION	Allocation	SERVCIE CUSTOMER
1	301-303	Total Intangible Plant	PISXGENL	$561,023
2		Total Steam Production		
3	310	Land & Land Rights	DPROD	$0
4	311	Structures & Improvements	DPROD	0
5	312	Boiler Plant Equipment	DPROD	0
6	313	Engines & Engine-Driven Generators	DPROD	0
7	314	Turbogenerator Units	DPROD	0
8	315	Accessory Electric Equipment	DPROD	0
9	316	Miscellaneous Power Plant Equipment	DPROD	0
10	114	San Juan & Irvington Acquistion Adjustment	DPROD	0
11	102	Electric Plant Purchased or Sold	DPROD	0
12		Total Steam Production		$0
13		Other Production Plant		
14	340	Land & Land Rights	DPROD	$0
15	341	Structures & Improvements	DPROD	0
16	342	Fuel Holders, Producers, & Accessories	DPROD	0
17	343	Prime Movers	DPROD	0
18	344	Generators	DPROD	0
19	345	Accessory Electric Equipment	DPROD	0
20		Miscellaneous Power Plant Equipment	DPROD	0
21		Total Other Production Plant		$0
22		Total Production Plant		$0
23	350-359	Transmission	DTRAN	$0
24	XXX	Intentionally Blank	DTRAN	0
25		Total Transmission Plant		$0
26		Distribution Plant		
27	360	Land & Rights	DDISPSUB	$0.00
28	361	Structures & Improvements	DDISPSUB	$0
29	362	Station Equipment	DDISPSUB	0
30	364	Poles, Towers, & Fixtures	DDISPOLE	11,967,407
31	365	Overhead Conductors & Devices	DDISTCON	5,951,778
32	366	Underground Conduit	DDISTUCON	4,867,693
33	367	Underground Conductors & Devices	DDISTUDEV	3,656,455
34	368	Line Transformers	DDISTLINET	10,511,724
35	369	Services	CUST	209,035
36	370	Meters	CMETERS	1,338,326
37	373	Street Lighting & Signal Systems	DDISTLTG	0
38	374	Asset Retirement Obligation	DDISPSUB	0
39		Total Distribution Plant		$38,502,419

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - RATE BASE ALLOCATION TO CLASSES OF SERVICES
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCOUNT	FERC ACCOUNT DESCRIPTION	Allocation	SERVCIE CUSTOMER
		TOTAL PLANT IN SERVICE EXCLUDING INTANGIBLE & GENERAL PLANT		
1				
2				$38,502,419
3	389-398	Total General Plant	PISXGENL	$2,726,497
4				
5		TOTAL ELECTRIC PLANT IN SERVICE		
6				$41,789,939
7		Less: Accumulated Depreciation		
8		Total Intangible Plant AD	PISXGENL	$182,960
9		Production Plant		$0
10		Other Production Plant		$0
11		Total Production Plant AD	DPROD	$0
12		Transmission Non-EHV (138 KV & below) AD	DTNEHV	$0
13		Transmission EHV (345 KV & above) AD	DTEHV	0
14		Total Transmission Plant		$0
15		Distribution Plant AD		
16	360	Land & Rights	DDISPSUB	$0.00
17	361	Structures & Improvements	PLT361	$0
18	362	Station Equipment	PLT362	$0
19	364	Poles, Towers, & Fixtures	PLT364	$9,549,050
20	365	Overhead Conductors & Devices	PLT365	$3,772,041
21	366	Underground Conduit	PLT366	$2,220,211
22	367	Underground Conductors & Devices	PLT367	$1,904,545
23	368	Line Transformers	PLT368	6,315,466
24	369	Services	PLT369	122,745
25	370	Meters	PLT370	(333,126)
26	373	Street Lighting & Signal Systems	PLT373	0
27	374	Asset Retirement Obligation	DDISPSUB	0
28		Total Distribution AD		$23,550,932
29		General Plant Accumulated Depreciation	GENLPIS	$1,262,277
30		TOTAL ACCUMULATED DEPRECIATION		$24,996,169

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - RATE BASE ALLOCATION TO CLASSES OF SERVICES
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCOUNT	FERC ACCOUNT DESCRIPTION	Allocation	SERVCIE CUSTOMER
1		TOTAL NET PLANT IN SERVICE		$16,793,770
2		Working Capital		
3	n/a	Cash Working Capital	OM	($381,430)
4	151, 152	Fuel Inventory	EPROD	$0
5	154, 163	Materials & Supplies	OM	$833,028
6	165	Prepayments	OM	$54,558
7		Total Working Capital		$506,156
8		Less: Customer Contributions		
9	252	Customer Advances for Construction	DCUSTADV	$0
10	235	Customer Deposits	DCUSTDEP	$0
11	230&253	Deferred Credits - Asset Retirement	TOTPIS	(49,190)
12		Total Less: Customer Contributions		($49,190)
13		Other Rate Base		
14	105.0	Plant Held for Future Use - Transmission Plant	DTNEHV	$0
15	182.3	Regulatory Assets	DISTPIS	$0
16	254	Regulatory Liabilities	DISTPIS	$0
17		Total Other Rate Base		$0
18		Less: Accumulated Deferred Taxes (ADIT)		
19	190	ADIT	TOTPIS	$1,107,309
20	282	ADIT - Other Property	TOTPIS	($3,687,228)
21		Total Accumulated Deferred Taxes		($2,579,918)
22		TOTAL RATE BASE		$14,670,817

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - RATE BASE ALLOCATION TO CLASSES OF SERVICES
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCOUNT	FERC ACCOUNT DESCRIPTION	Allocation	LARGE POWER SERVICE DEMAND	LARGE POWER SERVICE ENERGY	LARGE POWER SERVICE CUSTOMER	LIGHTING DEMAND	LIGHTING ENERGY	LIGHTING CUSTOMER
1	301-303	Total Intangible Plant	PISXGENL	$107,222	$0	$140	$66,626	$0	$3,382
2		Total Steam Production							
3	310	Land & Land Rights	DPROD	$0	$0	$0	$0	$0	$0
4	311	Structures & Improvements	DPROD	0	0	0	0	0	0
5	312	Boiler Plant Equipment	DPROD	0	0	0	0	0	0
6	313	Engines & Engine-Driven Generators	DPROD	0	0	0	0	0	0
7	314	Turbogenerator Units	DPROD	0	0	0	0	0	0
8	315	Accessory Electric Equipment	DPROD	0	0	0	0	0	0
9	316	Miscellaneous Power Plant Equipment	DPROD	0	0	0	0	0	0
10	114	San Juan & Irvington Acquistion Adjustment	DPROD	0	0	0	0	0	0
11	102	Electric Plant Purchased or Sold	DPROD	0	0	0	0	0	0
12		Total Steam Production		$0	$0	$0	$0	$0	$0
13		Other Production Plant							
14	340	Land & Land Rights	DPROD	($5,322)	$0	$0	($205)	$0	$0
15	341	Structures & Improvements	DPROD	289,904	0	0	11,144	0	0
16	342	Fuel Holders, Producers, & Accessories	DPROD	119,644	0	0	4,599	0	0
17	343	Prime Movers	DPROD	2,641,478	0	0	101,537	0	0
18	344	Generators	DPROD	3,129,769	0	0	120,307	0	0
19	345	Accessory Electric Equipment	DPROD	574,074	0	0	22,067	0	0
20		Miscellaneous Power Plant Equipment	DPROD	608,981	0	0	23,409	0	0
21		Total Other Production Plant		$7,358,528	$0	$0	$282,858	$0	$0
22		Total Production Plant		$7,358,528	$0	$0	$282,858	$0	$0
23	350-359	Transmission	DTRAN	$0	$0	$0	$0	$0	$0
24	XXX	Intentionally Blank	DTRAN	0	0	0	0	0	0
25		Total Transmission Plant		$0	$0	$0	$0	$0	$0
26		Distribution Plant							
27	360	Land & Rights	DDISPSUB	$0.00	$0.00	$0.00	$1,409.18	$0.00	$0.00
28	361	Structures & Improvements	DDISPSUB	$0	$0	$0	$10,235	$0	$0
29	362	Station Equipment	DDISPSUB	0	0	0	97,850	0	0
30	364	Poles, Towers, & Fixtures	DDISPOLE	0	0	0	50,102	0	75,153
31	365	Overhead Conductors & Devices	DDISTCON	0	0	0	69,413	0	37,376
32	366	Underground Conduit	DDISTUCON	0	0	0	0	0	30,568
33	367	Underground Conductors & Devices	DDISTUDEV	0	0	0	42,644	0	22,962
34	368	Line Transformers	DDISTLINET	0	0	0	44,008	0	66,012
35	369	Services	CUST	0	0	603	0	0	0
36	370	Meters	CMETERS	0	0	9,035	0	0	0
37	373	Street Lighting & Signal Systems	DDISTLTG	0	0	0	3,973,928	0	0
38	374	Asset Retirement Obligation	DDISPSUB	0	0	0	0	0	0
39		Total Distribution Plant		$0	$0	$9,638	$4,289,589	$0	$232,071

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - RATE BASE ALLOCATION TO CLASSES OF SERVICES
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCOUNT	FERC ACCOUNT DESCRIPTION	Allocation	LARGE POWER SERVICE DEMAND	LARGE POWER SERVICE ENERGY	LARGE POWER SERVICE CUSTOMER	LIGHTING DEMAND	LIGHTING ENERGY	LIGHTING CUSTOMER
		TOTAL PLANT IN SERVICE EXCLUDING INTANGIBLE & GENERAL PLANT							
1				$7,358,528	$0	$9,638	$4,572,447	$0	$232,071
2									
3	389-398	Total General Plant	PISXGENL	$521,084	$0	$683	$323,792	$0	$16,434
4									
5		TOTAL ELECTRIC PLANT IN SERVICE		$7,986,834	$0	$10,461	$4,962,865	$0	$251,887
6									
7		Less: Accumulated Depreciation							
8		Total Intangible Plant AD	PISXGENL	$34,967	$0	$46	$21,728	$0	$1,103
9		Production Plant		$0	$0	$0	$0	$0	$0
10		Other Production Plant		$1,593,639	$0	$0	$61,259	$0	$0
11		Total Production Plant AD	DPROD	$1,593,639	$0	$0	$61,259	$0	$0
12		Transmission Non-EHV (138 KV & below) AD	DTNEHV	$0	$0	$0	$0	$0	$0
13		Transmission EHV (345 KV & above) AD	DTEHV	0	0	0	0	0	0
14		Total Transmission Plant		$0	$0	$0	$0	$0	$0
15		Distribution Plant AD							
16	360	Land & Rights	DDISPSUB	$0.00	$0.00	$0.00	$98.23	$0.00	$0.00
17	361	Structures & Improvements	PLT361	$0	$0	$0	$3,971	$0	$0
18	362	Station Equipment	PLT362	$0	$0	$0	$40,684	$0	$0
19	364	Poles, Towers, & Fixtures	PLT364	$0	$0	$0	$39,978	$0	$59,966
20	365	Overhead Conductors & Devices	PLT365	$0	$0	$0	$43,992	$0	$23,688
21	366	Underground Conduit	PLT366	$0	$0	$0	$0	$0	$13,943
22	367	Underground Conductors & Devices	PLT367	$0	$0	$0	$22,212	$0	$11,960
23	368	Line Transformers	PLT368	0	0	0	26,440	0	39,660
24	369	Services	PLT369	0	0	354	0	0	0
25	370	Meters	PLT370	0	0	(2,249)	0	0	0
26	373	Street Lighting & Signal Systems	PLT373	0	0	0	2,952,870	0	0
27	374	Asset Retirement Obligation	DDISPSUB	0	0	0	0	0	0
28		Total Distribution AD		$0	$0	($1,895)	$3,130,243	$0	$149,217
29		General Plant Accumulated Depreciation	GENLPIS	$241,245	$0	$316	$149,905	$0	$7,608
30		TOTAL ACCUMULATED DEPRECIATION		$1,869,850	$0	($1,533)	$3,363,135	$0	$157,928

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - RATE BASE ALLOCATION TO CLASSES OF SERVICES
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCOUNT	FERC ACCOUNT DESCRIPTION	Allocation	LARGE POWER SERVICE DEMAND	LARGE POWER SERVICE ENERGY	LARGE POWER SERVICE CUSTOMER	LIGHTING DEMAND	LIGHTING ENERGY	LIGHTING CUSTOMER
1		TOTAL NET PLANT IN SERVICE		$6,116,984	$0	$11,995	$1,599,730	$0	$93,959
2		Working Capital							
3	n/a	Cash Working Capital	OM	($72,898)	$0	($95)	($45,298)	$0	($2,299)
4	151, 152	Fuel Inventory	EPROD	$11,700	$0	$0	$450	$0	$0
5	154, 163	Materials & Supplies	OM	$159,207	$0	$209	$98,928	$0	$5,021
6	165	Prepayments	OM	$10,427	$0	$14	$6,479	$0	$329
7		Total Working Capital		$108,435	$0	$127	$60,559	$0	$3,051
8		Less: Customer Contributions							
9	252	Customer Advances for Construction	DCUSTADV	$0	$0	$0	$0	$0	$0
10	235	Customer Deposits	DCUSTDEP	$0	$0	$0	$0	$0	$0
11	230&253	Deferred Credits - Asset Retirement	TOTPIS	(3,234)	0	(2,687)	(2,109)	0	(1,752)
12		Total Less: Customer Contributions		($3,234)	$0	($2,687)	($2,109)	$0	($1,752)
13		Other Rate Base							
14	105.0	Plant Held for Future Use - Transmission Plant	DTNEHV	$0	$0	$0	$0	$0	$0
15	182.3	Regulatory Assets	DISTPIS	$0	$0	$0	$0	$0	$0
16	254	Regulatory Liabilities	DISTPIS	$0	$0	$0	$0	$0	$0
17		Total Other Rate Base		$0	$0	$0	$0	$0	$0
18		Less: Accumulated Deferred Taxes (ADIT)							
19	190	ADIT	TOTPIS	$211,627	$0	$277	$131,501	$0	$6,674
20	282	ADIT - Other Property	TOTPIS	($704,698)	$0	($923)	($437,886)	$0	($22,225)
21		Total Accumulated Deferred Taxes		($493,070)	$0	($646)	($306,384)	$0	($15,550)
22		TOTAL RATE BASE		$5,729,115	$0	$8,789	$1,351,797	$0	$79,707

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCOUNT	FERC ACCOUNT DESCRIPTION	Allocation	TOTAL UNSE	RESIDENTIAL	SMALL GENERAL SERVICE	MED./LRG. GENERAL SERVICE	LARGE POWER SERVICE	LIGHTING
1		**Steam Power Generation Expense**							
2	500	Operation Supervision & Engineering	DPROD	$0	$0	$0	$0	$0	$0
3	501	501-FUEL PPFAC ELIGIBLE	EFUEL	0	0	0	0	0	0
4	502	Steam Expenses	DPROD	0	0	0	0	0	0
5	505	Electric Expenses	DPROD	0	0	0	0	0	0
6	506	Miscellaneous Steam Power Expenses	DPROD	0	0	0	0	0	0
7	507	Rents	DPROD	0	0	0	0	0	0
8	510	Maintenance Supervision & Engineering	DPROD	0	0	0	0	0	0
9	511	Maintenance of Structures	DPROD	0	0	0	0	0	0
10	512	Maintenance of Boiler Plant	DPROD	0	0	0	0	0	0
11	513	Maintenance of Electric Plant	DPROD	0	0	0	0	0	0
12	514	Maintenance Miscellaneous Steam Plant	DPROD	0	0	0	0	0	0
13	411	FAS 143 Accretion Expense	DPROD	0	0	0	0	0	0
14	412	Loss from Disposition of Utility Plant	DPROD	0	0	0	0	0	0
15		**Total Steam Power Generation Expense**		$0	$0	$0	$0	$0	$0
16		**Other Power Generation Expense**							
17	546	Operation Supervision & Engineering	DPROD	$3,405,721	$2,059,532	$292,982	$903,522	$144,145	$5,541
18	547	PPFAC - Fuel	EFUEL	5,543,690	2,876,726	412,514	1,952,621	299,177	2,651
19	548 & 549	Generation Exp & Misc Other Power Generation	DPROD	669,155	404,656	57,565	177,524	28,322	1,089
20	550	Rents	DPROD	0	0	0	0	0	0
21	551	Maintenance Supervision & Engineering	DPROD	6,512	3,938	560	1,728	276	11
22	552-554	Maintenance Structures, Generating, Other	DPROD	1,384,519	837,256	119,105	367,306	58,599	2,253
23	407	Regulatory Asset Amortization	DPROD	3,100,000	1,874,654	266,682	822,416	131,206	5,043
24		Total Other Power Generation Expense		$14,109,597	$8,056,761	$1,149,408	$4,225,117	$661,724	$16,587
25		**Total Production Expense**		$14,109,597	$8,056,761	$1,149,408	$4,225,117	$661,724	$16,587
26		**Other Power Supply Expense**							
27		PPFAC - Purchased Power							
28	555	PPFAC - DEMAND	EPROD	$0	$0	$0	$0	$0	$0
29	555	PPFAC - ENERGY	EFUEL	62,964,670	32,673,564	4,685,296	22,177,679	3,398,027	30,105
30		TOTAL PURCHASED POWER		$62,964,670	$32,673,564	$4,685,296	$22,177,679	$3,398,027	$30,105
31	556	System Control and Load Dispatching	DPROD	$0	$0	$0	$0	$0	$0
32	557	Other Expenses and Accretion Expense	DPROD	916543	554,258	78,847	243,154	38,792	1,491
33		**Total Power Supply Expense**		$63,881,212	$33,227,822	$4,764,143	$22,420,833	$3,436,819	$31,596
34	565	Trans of Electricity by Others - PPFAC Eligible	EFUEL	9,014,026	$4,677,549	$670,747	$3,174,958	$486,462	$4,310
35	565	Trans of Electricity by Others - PPFAC Non-Eligible	DTRAN	14,531,456	8,787,564	1,250,088	3,855,128	615,035	23,642
36		**Total Transmission Plant**		$23,545,482	$13,465,114	$1,920,835	$7,030,085	$1,101,497	$27,951

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCOUNT	FERC ACCOUNT DESCRIPTION	Allocation	TOTAL UNSE	RESIDENTIAL	SMALL GENERAL SERVICE	MED./LRG. GENERAL SERVICE	LARGE POWER SERVICE	LIGHTING
1		Distribution Plant							
2	580	Operation Supervision & Engineering	LAB58189	$416,745	$266,542	$37,879	$111,623	$0	$701
3	581	Load Dispatching	DISTPIS	860,035	538,656	76,549	225,579	0	19,250
4	582	Station Expenses	DISTPIS	69,023	43,230	6,143	18,104	0	1,545
5	583	Overhead Line Expenses	OHDIST	542,487	346,965	49,307	145,302	0	912
6	584	Underground Line Expenses	UGDIST	309,851	198,175	28,163	82,992	0	521
7	585	Street Lighting & Signal System Expenses	DDISTLTG	0	0	0	0	0	0
8	586	Meter Expenses	CMETERS	721,222	125,478	462,393	132,458	894	0
9	587	Customer Installations Expense	CMETERS	76,287	13,272	48,909	14,011	95	0
10	588	Miscellaneous Distribution Expenses	DISTPIS	756,371	483,761	68,748	202,590	0	1,272
11	589	Rents	DISTPIS	26,605	16,663	2,368	6,978	0	596
12	590	Maintenance Supervision & Engineering	LAB59198	25	16	2	7	0	0
13	591	Maintenance of Structures	DISTPIS	0	0	0	0	0	0
14	592	Maintenance of Station Equipment	DISTPIS	903,797	566,065	80,444	237,057	0	20,230
15	593	Maintenance of Overhead Lines	OHDIST	589,548	377,064	53,585	157,907	0	992
16	594	Maintenance of Underground Lines	UGDIST	102,120	65,314	9,282	27,352	0	172
17	595	Maintenance of Line Transformers	PLT368	92,619	59,237	8,418	24,807	0	156
18	596	Maintenance of Street Lighting & Signal Systems	DDISTLTG	27,094	0	0	0	0	27,094
19	597	Maintenance of Meters	CMETERS	2,080	362	1,334	382	3	0
20	598	Maintenance of Miscellaneous Distribution Plant	DISTPIS	14,028	8,875	1,423	3,549	0	181
21	407	Regulatory Asset Amortization	DISTPIS	0	0	0	0	0	0
22		Total Distribution Plant		$5,509,935	$3,109,676	$934,946	$1,390,698	$992	$73,622
23		Customer Account Expense							
24	901&907	Supervision	CSUPV	$353,018	$306,501	$32,495	$5,146	$15	$8,861
24	902	Meter Reading Expenses	CREAD	651,708	580,400	61,534	9,745	28	0
25	903	Customer Records & Collection Expenses	CBILLCOL	2,889,804	2,509,015	266,007	42,127	121	72,533
26	904	Uncollectible Accounts	EUNCOL	505,677	242,660	44,550	191,620	23,172	3,673
27	905	Customer Accounts Expenses Supervision	LAB900	(2,533)	(2,199)	(233)	(37)	(0)	(64)
28	908	Customer Assistance Expenses	CCUSINFO	121,102	105,145	11,147	1,765	5	3,040
29	909	Informational and Instructional Advertising Expenses	CCUSINFO	407,788	354,054	37,537	5,945	17	10,235
30	910	Miscellaneous Customer Service & Informational Expenses	CCUSINFO	2,496	2,167	230	36	0	63
31		Total Customer Account Expense		$4,929,060	$4,097,743	$453,268	$256,349	$23,359	$98,341
32		Total Operation and Maintenance Expense Excluding Fuel & Power Supply Expense & A&G		$42,550,384	$25,852,569	$4,045,943	$10,949,628	$1,488,394	$213,850
33	920-935	Administrative and General Expense	OMXGENL	$8,409,208	$5,479,419	$937,779	$1,722,621	$203,587	$65,803
34		Total Operation and Maintenance Expense		$120,384,494	$67,436,536	$10,160,378	$37,045,703	$5,427,977	$313,899

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCOUNT	FERC ACCOUNT DESCRIPTION	Allocation	TOTAL UNSE	RESIDENTIAL	SMALL GENERAL SERVICE	MED./LRG. GENERAL SERVICE	LARGE POWER SERVICE	LIGHTING
		Depreciation and Amortization							
1	301-303	Total Intangible Plant Depreciation Expense	PISXGENL	$1,836,827	$1,145,098	$176,935	$472,185	$25,792	$16,818
2	500-547	Production Depreciation Expense	DPROD	$4,912,792	$2,970,898	$422,629	$1,303,341	$207,931	$7,993
3		Transmission NonEHV	DTNEHV	$0	$0	$0	$0	$0	$0
4		Transmission EHV	DTEHV	0	0	0	0	0	0
5		Total Transmission Depreciation Expense		$0	$0	$0	$0	$0	$0
		Distribution Plant Depreciation Expense							
6	360	Land & Rights	PLT360	$1,070	$685	$97	$287	$0	$2
7	361	Structures & Improvements	PLT361	85,623	54,763	7,782	22,934	0	144
8	362	Station Equipment	PLT362	913,346	584,160	83,015	244,635	0	1,536
9	364	Poles, Towers, & Fixtures	PLT364	652,041	417,033	59,265	174,646	0	1,097
10	365	Overhead Conductors & Devices	PLT365	734,953	470,063	66,801	196,853	0	1,236
11	366	Underground Conduit	PLT366	211,032	134,973	19,181	56,524	0	355
12	367	Underground Conductors & Devices	PLT367	546,264	349,381	49,651	146,314	0	919
13	368	Line Transformers	PLT368	1,276,133	816,191	115,990	341,805	0	2,146
14	369	Services	PLT369	155,540	138,521	14,686	2,326	7	0
15	370	Meters	PLT370	220,357	38,338	141,276	40,470	273	0
16	373	Street Lighting & Signal Systems	PLT373	54,913	0	0	0	0	54,913
17		Other	DISTPIS	-	0	0	0	0	0
18		Total All Distribution Depreciation Expense		$4,851,273	$3,004,106	$557,744	$1,226,793	$280	$62,349
19		General Plant Depreciation Expense	GENLPIS	$1,458,632	$909,327	$140,505	$374,964	$20,481	$13,355
20		Total Depreciation Expense		$13,059,523	$8,029,429	$1,297,813	$3,377,283	$254,484	$100,515
21		Taxes Other Than Income Taxes							
22	408	Property Tax - Production	DPROD	$1,444,855	$873,743	$124,296	$383,313	$61,153	$2,351
23	408	Property Tax - Transmission	DTNEHV	0	0	0	0	0	0
24	408	Property Tax - Transmission	DTEHV	0	0	0	0	0	0
25	408	Property Tax - Distribution	DISTPIS	4,010,589	2,537,374	406,793	1,014,629	110	51,683
26	408	Property Tax - General	GENLPIS	234,225	146,019	22,562	60,211	3,289	2,145
27	408	Payroll	TOTPIS	360,900	224,989	34,764	92,775	5,068	3,304
28	408	Medical and Dental	TOTPIS	83,077	51,791	8,003	21,356	1,167	761
29	408	Other	TOTPIS	15,775	9,834	1,519	4,055	221	144
30		Total Taxes Other Than Income Taxes		$6,149,421	$3,843,749	$597,937	$1,576,340	$71,007	$60,388
31		Interest on Customer Deposits							
32	431	Customer Deposit Interest Expense	DISTPIS	$7,440	$3,677	$3,249	$514	$0	$0
33		Income Taxes							
34	409	Current Income Tax - State & Federal	TOTPIS	$1,291,053	$804,856	$124,362	$331,885	$18,128	$11,821
35		Total Operating Expense - Excluding Income Taxes		$139,600,878	$79,313,391	$12,059,377	$41,999,840	$5,753,469	$474,802
36		Total Operating Expense - Including Taxes		$140,891,931	$80,118,247	$12,183,739	$42,331,725	$5,771,597	$486,623

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCOUNT	FERC ACCOUNT DESCRIPTION	Allocation	RESIDENTIAL STANDARD SERVICE DEMAND	ENERGY	CUSTOMER	BLANK DEMAND	ENERGY	CUSTOMER	SMALL GENERAL SERVICE DEMAND	ENERGY	CUSTOMER
1		**Steam Power Generation Expense**										
2	500	Operation Supervision & Engineering	DPROD	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	501	501-FUEL PPFAC ELIGIBLE	EFUEL	0	0	0	0	0	0	0	0	0
4	502	Steam Expenses	DPROD	0	0	0	0	0	0	0	0	0
5	505	Electric Expenses	DPROD	0	0	0	0	0	0	0	0	0
6	506	Miscellaneous Steam Power Expenses	DPROD	0	0	0	0	0	0	0	0	0
7	507	Rents	DPROD	0	0	0	0	0	0	0	0	0
8	510	Maintenance Supervision & Engineering	DPROD	0	0	0	0	0	0	0	0	0
9	511	Maintenance of Structures	DPROD	0	0	0	0	0	0	0	0	0
10	512	Maintenance of Boiler Plant	DPROD	0	0	0	0	0	0	0	0	0
11	513	Maintenance of Electric Plant	DPROD	0	0	0	0	0	0	0	0	0
12	514	Maintenance Miscellaneous Steam Plant	DPROD	0	0	0	0	0	0	0	0	0
13	411	FAS 143 Accretion Expense	DPROD	0	0	0	0	0	0	0	0	0
14	412	Loss from Disposition of Utility Plant	DPROD	0	0	0	0	0	0	0	0	0
15		**Total Steam Power Generation Expense**		$0	$0	$0	$0	$0	$0	$0	$0	$0
16		**Other Power Generation Expense**										
17	546	Operation Supervision & Engineering	DPROD	$2,059,532	$0	$0	$0	$0	$0	$292,982	$0	$0
18	547	PPFAC - Fuel	EFUEL	$0	$2,876,726	$0	$0	$0	$0	0	412,514	0
19	548 & 549	Generation Exp & Misc Other Power Generation	DPROD	$404,656	$0	$0	$0	$0	$0	57,565	0	0
20	550	Rents	DPROD	$0	$0	$0	$0	$0	$0	0	0	0
21	551	Maintenance Supervision & Engineering	DPROD	$3,938	$0	$0	$0	$0	$0	560	0	0
22	552-554	Maintenance Structures, Generating, Other	DPROD	$837,256	$0	$0	$0	$0	$0	119,105	0	0
23	407	Regulatory Asset Amortization	DPROD	$1,874,654	$0	$0	$0	$0	$0	266,682	0	0
24		Total Other Power Generation Expense		$5,180,036	$2,876,726	$0	$0	$0	$0	$736,893	$412,514	$0
25		**Total Production Expense**		$5,180,036	$2,876,726	$0	$0	$0	$0	$736,893	$412,514	$0
26		**Other Power Supply Expense**										
27		PPFAC - Purchased Power										
28	555	PPFAC - DEMAND	EPROD	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	555	PPFAC - ENERGY	EFUEL	$0	$32,673,564	$0	$0	$0	$0	0	4,685,296	0
30		TOTAL PURCHASED POWER		$0	$32,673,564	$0	$0	$0	$0	$0	$4,685,296	$0
31	556	System Control and Load Dispatching	DPROD	$0	$0	$0	$0	$0	$0	$0	$0	$0
32	557	Other Expenses and Accretion Expense	DPROD	554,258	-	-	-	-	-	78,847	-	-
33		**Total Power Supply Expense**		$554,258	$32,673,564	$0	$0	$0	$0	$78,847	$4,685,296	$0
34	565	Trans of Electricity by Others - PPFAC Eligible	EFUEL	$0	$4,677,549	$0	$0	$0	$0	$0	$670,747	$0
35	565	Trans of Electricity by Others - PPFAC Non-Eligible	DTRAN	8,787,564	0	0	0	0	0	1,250,088	0	0
36		**Total Transmission Plant**		$8,787,564	$4,677,549	$0	$0	$0	$0	$1,250,088	$670,747	$0

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FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCOUNT	FERC ACCOUNT DESCRIPTION	Allocation	RESIDENTIAL STANDARD SERVICE DEMAND	ENERGY	CUSTOMER	BLANK DEMAND	ENERGY	CUSTOMER	SMALL GENERAL SERVICE DEMAND	ENERGY	CUSTOMER
1		Distribution Plant										
2	580	Operation Supervision & Engineering	LAB58189	$173,252	$0	$93,290	$0	$0	$0	$24,621	$0	$13,257
3	581	Load Dispatching	DISTPIS	538,656	0	0	0	0	0	76,549	0	0
4	582	Station Expenses	DISTPIS	43,230	0	0	0	0	0	6,143	0	0
5	583	Overhead Line Expenses	OHDIST	225,527	0	121,438	0	0	0	32,050	0	17,258
6	584	Underground Line Expenses	UGDIST	0	0	198,175	0	0	0	0	0	28,163
7	585	Street Lighting & Signal System Expenses	DDISTLTG	0	0	0	0	0	0	0	0	0
8	586	Meter Expenses	CMETERS	0	0	125,478	0	0	0	0	0	462,393
9	587	Customer Installations Expense	CMETERS	0	0	13,272	0	0	0	0	0	48,909
10	588	Miscellaneous Distribution Expenses	DISTPIS	193,504	0	290,257	0	0	0	27,499	0	41,249
11	589	Rents	DISTPIS	16,663	0	0	0	0	0	2,368	0	0
12	590	Maintenance Supervision & Engineering	LAB59198	10	0	6	0	0	0	1	0	1
13	591	Maintenance of Structures	DISTPIS	0	0	0	0	0	0	0	0	0
14	592	Maintenance of Station Equipment	DISTPIS	566,065	0	0	0	0	0	80,444	0	0
15	593	Maintenance of Overhead Lines	OHDIST	245,092	0	131,972	0	0	0	34,830	0	18,755
16	594	Maintenance of Underground Lines	UGDIST	0	0	65,314	0	0	0	0	0	9,282
17	595	Maintenance of Line Transformers	PLT368	23,695	0	35,542	0	0	0	3,367	0	5,051
18	596	Maintenance of Street Lighting & Signal Systems	DDISTLTG	0	0	0	0	0	0	0	0	0
19	597	Maintenance of Meters	CMETERS	0	0	362	0	0	0	0	0	1,334
20	598	Maintenance of Miscellaneous Distribution Plant	DISTPIS	4,799	0	4,076	0	0	0	682	0	741
21	407	Regulatory Asset Amortization	DISTPIS	0	0	0	0	0	0	0	0	0
22		Total Distribution Plant		$2,030,494	$0	$1,079,182	$0	$0	$0	$288,555	$0	$646,391
23		Customer Account Expense										
24	901&907	Supervision	CSUPV	$0	$0	$306,501	$0	$0	$0	$0	$0	$32,495
24	902	Meter Reading Expenses	CREAD	0	0	580,400	0	0	0	0	0	61,534
25	903	Customer Records & Collection Expenses	CBILLCOL	0	0	2,509,015	0	0	0	0	0	266,007
26	904	Uncollectible Accounts	EUNCOL	242,660	0	0	0	0	0	44,550	0	0
27	905	Customer Accounts Expenses Supervision	LAB900	0	0	(2,199)	0	0	0	0	0	(233)
28	908	Customer Assistance Expenses	CCUSINFO	0	0	105,145	0	0	0	0	0	11,147
29	909	Informational and Instructional Advertising Expenses	CCUSINFO	0	0	354,054	0	0	0	0	0	37,537
30	910	Miscellaneous Customer Service & Informational Expenses	CCUSINFO	0	0	2,167	0	0	0	0	0	230
31		Total Customer Account Expense		$242,660	$0	$3,855,083	$0	$0	$0	$44,550	$0	$408,718
32		Total Operation and Maintenance Expense Excluding Fuel & Power Supply Expense & A&G		$16,240,755	$4,677,549	$4,934,265	$0	$0	$0	$2,320,087	$670,747	$1,055,109
33	920-935	Administrative and General Expense	OMXGENL	$3,295,458	$0	$2,183,961	$0	$0	$0	$470,775	$0	$467,003
34		Total Operation and Maintenance Expense		$20,090,471	$40,227,839	$7,118,226	$0	$0	$0	$2,869,709	$5,768,557	$1,522,112

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCOUNT	FERC ACCOUNT DESCRIPTION	Allocation	RESIDENTIAL STANDARD SERVICE DEMAND	RESIDENTIAL STANDARD SERVICE ENERGY	RESIDENTIAL STANDARD SERVICE CUSTOMER	BLANK DEMAND	BLANK ENERGY	BLANK CUSTOMER	SMALL GENERAL SERVICE DEMAND	SMALL GENERAL SERVICE ENERGY	SMALL GENERAL SERVICE CUSTOMER
		Depreciation and Amortization										
1	301-303	Total Intangible Plant Depreciation Expense	PISXGENL	$788,186	$0	$356,912	$0	$0	$0	$112,063	$0	$64,871
2	500-547	Production Depreciation Expense	DPROD	$2,970,898	$0	$0	$0	$0	$0	$422,629	$0	$0
3		Transmission NonEHV	DTNEHV	$0	$0	$0	$0	$0	$0	$0	$0	$0
4		Transmission EHV	DTEHV	0	0	0	0	0	0	0	0	0
5		Total Transmission Depreciation Expense		$0	$0	$0	$0	$0	$0	$0	$0	$0
		Distribution Plant Depreciation Expense										
6	360	Land & Rights	PLT360	$685	$0	$0	$0	$0	$0	$97	$0	$0
7	361	Structures & Improvements	PLT361	54,763	0	0	0	0	0	7,782	0	0
8	362	Station Equipment	PLT362	584,160	0	0	0	0	0	83,015	0	0
9	364	Poles, Towers, & Fixtures	PLT364	166,813	0	250,220	0	0	0	23,706	0	35,559
10	365	Overhead Conductors & Devices	PLT365	305,541	0	164,522	0	0	0	43,421	0	23,380
11	366	Underground Conduit	PLT366	0	0	134,973	0	0	0	0	0	19,181
12	367	Underground Conductors & Devices	PLT367	227,097	0	122,283	0	0	0	32,273	0	17,378
13	368	Line Transformers	PLT368	326,476	0	489,715	0	0	0	46,396	0	69,594
14	369	Services	PLT369	0	0	138,521	0	0	0	0	0	14,686
15	370	Meters	PLT370	0	0	38,338	0	0	0	0	0	141,276
16	373	Street Lighting & Signal Systems	PLT373	0	0	0	0	0	0	0	0	0
17		Other	DISTPIS	0	0	0	0	0	0	0	0	0
18		Total All Distribution Depreciation Expense		$1,665,535	$0	$1,338,571	$0	$0	$0	$236,690	$0	$321,054
19		General Plant Depreciation Expense	GENLPIS	$625,901	$0	$283,425	$0	$0	$0	$88,990	$0	$51,515
20		Total Depreciation Expense		$6,050,520	$0	$1,978,909	$0	$0	$0	$860,373	$0	$437,440
21		Taxes Other Than Income Taxes										
22	408	Property Tax - Production	DPROD	$873,743	$0	$0	$0	$0	$0	$124,296	$0	$0
23	408	Property Tax - Transmission	DTNEHV	0	0	0	0	0	0	0	0	0
24	408	Property Tax - Transmission	DTEHV	0	0	0	0	0	0	0	0	0
25	408	Property Tax - Distribution	DISTPIS	1,371,942	0	1,165,432	0	0	0	194,968	0	211,826
26	408	Property Tax - General	GENLPIS	100,506	0	45,512	0	0	0	14,290	0	8,272
27	408	Payroll	TOTPIS	154,863	0	70,126	0	0	0	22,018	0	12,746
28	408	Medical and Dental	TOTPIS	35,649	0	16,143	0	0	0	5,068	0	2,934
29	408	Other	TOTPIS	6,769	0	3,065	0	0	0	962	0	557
30		Total Taxes Other Than Income Taxes		$2,543,471	$0	$1,300,278	$0	$0	$0	$361,602	$0	$236,335
31		Interest on Customer Deposits										
32	431	Customer Deposit Interest Expense	DISTPIS	$3,677	$0	$0	$0	$0	$0	$3,249	$0	$0
33		Income Taxes										
34	409	Current Income Tax - State & Federal	TOTPIS	$553,993	$0	$250,863	$0	$0	$0	$78,766	$0	$45,596
35		Total Operating Expense - Excluding Income Taxes		$28,688,139	$40,227,839	$10,397,413	$0	$0	$0	$4,094,932	$5,768,557	$2,195,887
36		Total Operating Expense - Including Taxes		$29,242,132	$40,227,839	$10,648,276	$0	$0	$0	$4,173,698	$5,768,557	$2,241,484

UNS ELECTRIC, INC.
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FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCOUNT	FERC ACCOUNT DESCRIPTION	Allocation	MEDIUM/LARGE GENERAL SERVCIE DEMAND	ENERGY	CUSTOMER	BLANK DEMAND	ENERGY	CUSTOMER
1		**Steam Power Generation Expense**							
2	500	Operation Supervision & Engineering	DPROD	$0	$0	$0	$0	$0	$0
3	501	501-FUEL PPFAC ELIGIBLE	EFUEL	0	0	0	0	0	0
4	502	Steam Expenses	DPROD	0	0	0	0	0	0
5	505	Electric Expenses	DPROD	0	0	0	0	0	0
6	506	Miscellaneous Steam Power Expenses	DPROD	0	0	0	0	0	0
7	507	Rents	DPROD	0	0	0	0	0	0
8	510	Maintenance Supervision & Engineering	DPROD	0	0	0	0	0	0
9	511	Maintenance of Structures	DPROD	0	0	0	0	0	0
10	512	Maintenance of Boiler Plant	DPROD	0	0	0	0	0	0
11	513	Maintenance of Electric Plant	DPROD	0	0	0	0	0	0
12	514	Maintenance Miscellaneous Steam Plant	DPROD	0	0	0	0	0	0
13	411	FAS 143 Accretion Expense	DPROD	0	0	0	0	0	0
14	412	Loss from Disposition of Utility Plant	DPROD	0	0	0	0	0	0
15		**Total Steam Power Generation Expense**		$0	$0	$0	$0	$0	$0
16		**Other Power Generation Expense**							
17	546	Operation Supervision & Engineering	DPROD	$903,522	$0	$0	$0	$0	$0
18	547	PPFAC - Fuel	EFUEL	0	1,952,621	0	0	0	0
19	548 & 549	Generation Exp & Misc Other Power Generation	DPROD	177,524	0	0	0	0	0
20	550	Rents	DPROD	0	0	0	0	0	0
21	551	Maintenance Supervision & Engineering	DPROD	1,728	0	0	0	0	0
22	552-554	Maintenance Structures, Generating, Other	DPROD	367,306	0	0	0	0	0
23	407	Regulatory Asset Amortization	DPROD	822,416	0	0	0	0	0
24		Total Other Power Generation Expense		$2,272,495	$1,952,621	$0	$0	$0	$0
25		**Total Production Expense**		$2,272,495	$1,952,621	$0	$0	$0	$0
26		**Other Power Supply Expense**							
27		PPFAC - Purchased Power							
28	555	PPFAC - DEMAND	EPROD	$0	$0	$0	$0	$0	$0
29	555	PPFAC - ENERGY	EFUEL	0	22,177,679	0	0	0	0
30		TOTAL PURCHASED POWER		$0	$22,177,679	$0	$0	$0	$0
31	556	System Control and Load Dispatching	DPROD	$0	$0	$0	$0	$0	$0
32	557	Other Expenses and Accretion Expense	DPROD	243,154	-	-	-	-	-
33		**Total Power Supply Expense**		$243,154	$22,177,679	$0	$0	$0	$0
34	565	Trans of Electricity by Others - PPFAC Eligible	EFUEL	$0	$3,174,958	$0	$0	$0	$0
35	565	Trans of Electricity by Others - PPFAC Non-Eligible	DTRAN	3,855,128	0	0	0	0	0
36		**Total Transmission Plant**		$3,855,128	$3,174,958	$0	$0	$0	$0

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FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCOUNT	FERC ACCOUNT DESCRIPTION	Allocation	MEDIUM/LARGE GENERAL SERVCIE DEMAND	MEDIUM/LARGE GENERAL SERVCIE ENERGY	MEDIUM/LARGE GENERAL SERVCIE CUSTOMER	BLANK DEMAND	BLANK ENERGY	BLANK CUSTOMER
1		Distribution Plant							
2	580	Operation Supervision & Engineering	LAB58189	$72,555	$0	$39,068	$0	$0	$0
3	581	Load Dispatching	DISTPIS	225,579	0	0	0	0	0
4	582	Station Expenses	DISTPIS	18,104	0	0	0	0	0
5	583	Overhead Line Expenses	OHDIST	94,446	0	50,856	0	0	0
6	584	Underground Line Expenses	UGDIST	0	0	82,992	0	0	0
7	585	Street Lighting & Signal System Expenses	DDISTLTG	0	0	0	0	0	0
8	586	Meter Expenses	CMETERS	0	0	132,458	0	0	0
9	587	Customer Installations Expense	CMETERS	0	0	14,011	0	0	0
10	588	Miscellaneous Distribution Expenses	DISTPIS	81,036	0	121,554	0	0	0
11	589	Rents	DISTPIS	6,978	0	0	0	0	0
12	590	Maintenance Supervision & Engineering	LAB59198	4	0	2	0	0	0
13	591	Maintenance of Structures	DISTPIS	0	0	0	0	0	0
14	592	Maintenance of Station Equipment	DISTPIS	237,057	0	0	0	0	0
15	593	Maintenance of Overhead Lines	OHDIST	102,640	0	55,268	0	0	0
16	594	Maintenance of Underground Lines	UGDIST	0	0	27,352	0	0	0
17	595	Maintenance of Line Transformers	PLT368	9,923	0	14,884	0	0	0
18	596	Maintenance of Street Lighting & Signal Systems	DDISTLTG	0	0	0	0	0	0
19	597	Maintenance of Meters	CMETERS	0	0	382	0	0	0
20	598	Maintenance of Miscellaneous Distribution Plant	DISTPIS	2,010	0	1,539	0	0	0
21	407	Regulatory Asset Amortization	DISTPIS	0	0	0	0	0	0
22		Total Distribution Plant		$850,333	$0	$540,366	$0	$0	$0
23		Customer Account Expense							
24	901&907	Supervision	CSUPV	$0	$0	$5,146	$0	$0	$0
24	902	Meter Reading Expenses	CREAD	0	0	9,745	0	0	0
25	903	Customer Records & Collection Expenses	CBILLCOL	0	0	42,127	0	0	0
26	904	Uncollectible Accounts	EUNCOL	191,620	0	0	0	0	0
27	905	Customer Accounts Expenses Supervision	LAB900	0	0	(37)	0	0	0
28	908	Customer Assistance Expenses	CCUSINFO	0	0	1,765	0	0	0
29	909	Informational and Instructional Advertising Expenses	CCUSINFO	0	0	5,945	0	0	0
30	910	Miscellaneous Customer Service & Informational Expenses	CCUSINFO	0	0	36	0	0	0
31		Total Customer Account Expense		$191,620	$0	$64,728	$0	$0	$0
32		Total Operation and Maintenance Expense Excluding Fuel & Power Supply Expense & A&G		$7,169,576	$3,174,958	$605,094	$0	$0	$0
33	920-935	Administrative and General Expense	OMXGENL	$1,454,799	$0	$267,822	$0	$0	$0
34		Total Operation and Maintenance Expense		$8,867,529	$27,305,258	$872,916	$0	$0	$0

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCOUNT	FERC ACCOUNT DESCRIPTION	Allocation	MEDIUM/LARGE GENERAL SERVCIE DEMAND	ENERGY	CUSTOMER	BLANK DEMAND	ENERGY	CUSTOMER
		Depreciation and Amortization							
1	301-303	Total Intangible Plant Depreciation Expense	PISXGENL	$337,409	$0	$134,776	$0	$0	$0
2	500-547	Production Depreciation Expense	DPROD	$1,303,341	$0	$0	$0	$0	$0
3		Transmission NonEHV	DTNEHV	$0	$0	$0	$0	$0	$0
4		Transmission EHV	DTEHV	0	0	0	0	0	0
5		Total Transmission Depreciation Expense		$0	$0	$0	$0	$0	$0
		Distribution Plant Depreciation Expense							
6	360	Land & Rights	PLT360	$287	$0	$0	$0	$0	$0
7	361	Structures & Improvements	PLT361	22,934	0	0	0	0	0
8	362	Station Equipment	PLT362	244,635	0	0	0	0	0
9	364	Poles, Towers, & Fixtures	PLT364	69,858	0	104,787	0	0	0
10	365	Overhead Conductors & Devices	PLT365	127,955	0	68,899	0	0	0
11	366	Underground Conduit	PLT366	0	0	56,524	0	0	0
12	367	Underground Conductors & Devices	PLT367	95,104	0	51,210	0	0	0
13	368	Line Transformers	PLT368	136,722	0	205,083	0	0	0
14	369	Services	PLT369	0	0	2,326	0	0	0
15	370	Meters	PLT370	0	0	40,470	0	0	0
16	373	Street Lighting & Signal Systems	PLT373	0	0	0	0	0	0
17		Other	DISTPIS	0	0	0	0	0	0
18		Total All Distribution Depreciation Expense		$697,494	$0	$529,299	$0	$0	$0
19		General Plant Depreciation Expense	GENLPIS	$267,938	$0	$107,026	$0	$0	$0
20		Total Depreciation Expense		$2,606,182	$0	$771,101	$0	$0	$0
21		Taxes Other Than Income Taxes							
22	408	Property Tax - Production	DPROD	$383,313	$0	$0	$0	$0	$0
23	408	Property Tax - Transmission	DTNEHV	0	0	0	0	0	0
24	408	Property Tax - Transmission	DTEHV	0	0	0	0	0	0
25	408	Property Tax - Distribution	DISTPIS	574,543	0	440,086	0	0	0
26	408	Property Tax - General	GENLPIS	43,025	0	17,186	0	0	0
27	408	Payrolll	TOTPIS	66,294	0	26,481	0	0	0
28	408	Medical and Dental	TOTPIS	15,261	0	6,096	0	0	0
29	408	Other	TOTPIS	2,898	0	1,157	0	0	0
30		Total Taxes Other Than Income Taxes		$1,085,334	$0	$491,006	$0	$0	$0
31		Interest on Customer Deposits							
32	431	Customer Deposit Interest Expense	DISTPIS	$514	$0	$0	$0	$0	$0
33		Income Taxes							
34	409	Current Income Tax - State & Federal	TOTPIS	$237,155	$0	$94,730	$0	$0	$0
35		Total Operating Expense - Excluding Income Taxes		$12,559,560	$27,305,258	$2,135,022	$0	$0	$0
36		Total Operating Expense - Including Taxes		$12,796,715	$27,305,258	$2,229,752	$0	$0	$0

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCOUNT	FERC ACCOUNT DESCRIPTION	Allocation	
1		**Steam Power Generation Expense**		
2	500	Operation Supervision & Engineering	DPROD	
3	501	501-FUEL PPFAC ELIGIBLE	EFUEL	
4	502	Steam Expenses	DPROD	
5	505	Electric Expenses	DPROD	
6	506	Miscellaneous Steam Power Expenses	DPROD	
7	507	Rents	DPROD	
8	510	Maintenance Supervision & Engineering	DPROD	
9	511	Maintenance of Structures	DPROD	
10	512	Maintenance of Boiler Plant	DPROD	
11	513	Maintenance of Electric Plant	DPROD	
12	514	Maintenance Miscellaneous Steam Plant	DPROD	
13	411	FAS 143 Accretion Expense	DPROD	
14	412	Loss from Disposition of Utility Plant	DPROD	
15		**Total Steam Power Generation Expense**		
16		**Other Power Generation Expense**		
17	546	Operation Supervision & Engineering	DPROD	
18	547	PPFAC - Fuel	EFUEL	
19	548 & 549	Generation Exp & Misc Other Power Generation	DPROD	
20	550	Rents	DPROD	
21	551	Maintenance Supervision & Engineering	DPROD	
22	552-554	Maintenance Structures, Generating, Other	DPROD	
23	407	Regulatory Asset Amortization	DPROD	
24		Total Other Power Generation Expense		
25		**Total Production Expense**		
26		**Other Power Supply Expense**		
27		PPFAC - Purchased Power		
28	555	PPFAC - DEMAND	EPROD	
29	555	PPFAC - ENERGY	EFUEL	
30		TOTAL PURCHASED POWER		
31	556	System Control and Load Dispatching	DPROD	
32	557	Other Expenses and Accretion Expense	DPROD	
33		**Total Power Supply Expense**		
34	565	Trans of Electricity by Others - PPFAC Eligible	EFUEL	
35	565	Trans of Electricity by Others - PPFAC Non-Eligible	DTRAN	
36		**Total Transmission Plant**		

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCOUNT	FERC ACCOUNT DESCRIPTION	Allocation	
1		**Distribution Plant**		
2	580	Operation Supervision & Engineering	LAB58189	
3	581	Load Dispatching	DISTPIS	
4	582	Station Expenses	DISTPIS	
5	583	Overhead Line Expenses	OHDIST	
6	584	Underground Line Expenses	UGDIST	
7	585	Street Lighting & Signal System Expenses	DDISTLTG	
8	586	Meter Expenses	CMETERS	
9	587	Customer Installations Expense	CMETERS	
10	588	Miscellaneous Distribution Expenses	DISTPIS	
11	589	Rents	DISTPIS	
12	590	Maintenance Supervision & Engineering	LAB59198	
13	591	Maintenance of Structures	DISTPIS	
14	592	Maintenance of Station Equipment	DISTPIS	
15	593	Maintenance of Overhead Lines	OHDIST	
16	594	Maintenance of Underground Lines	UGDIST	
17	595	Maintenance of Line Transformers	PLT368	
18	596	Maintenance of Street Lighting & Signal Systems	DDISTLTG	
19	597	Maintenance of Meters	CMETERS	
20	598	Maintenance of Miscellaneous Distribution Plant	DISTPIS	
21	407	Regulatory Asset Amortization	DISTPIS	
22		**Total Distribution Plant**		
23		**Customer Account Expense**		
24	901&907	Supervision	CSUPV	
24	902	Meter Reading Expenses	CREAD	
25	903	Customer Records & Collection Expenses	CBILLCOL	
26	904	Uncollectible Accounts	EUNCOL	
27	905	Customer Accounts Expenses Supervision	LAB900	
28	908	Customer Assistance Expenses	CCUSINFO	
29	909	Informational and Instructional Advertising Expenses	CCUSINFO	
30	910	Miscellaneous Customer Service & Informational Expenses	CCUSINFO	
31		**Total Customer Account Expense**		
32		**Total Operation and Maintenance Expense Excluding Fuel & Power Supply Expense & A&G**		
33	920-935	**Administrative and General Expense**	OMXGENL	
34		**Total Operation and Maintenance Expense**		

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCOUNT	FERC ACCOUNT DESCRIPTION	Allocation	
		Depreciation and Amortization		
1	301-303	Total Intangible Plant Depreciation Expense	PISXGENL	
2	500-547	Production Depreciation Expense	DPROD	
3		Transmission NonEHV	DTNEHV	
4		Transmission EHV	DTEHV	
5		Total Transmission Depreciation Expense		
		Distribution Plant Depreciation Expense		
6	360	Land & Rights	PLT360	
7	361	Structures & Improvements	PLT361	
8	362	Station Equipment	PLT362	
9	364	Poles, Towers, & Fixtures	PLT364	
10	365	Overhead Conductors & Devices	PLT365	
11	366	Underground Conduit	PLT366	
12	367	Underground Conductors & Devices	PLT367	
13	368	Line Transformers	PLT368	
14	369	Services	PLT369	
15	370	Meters	PLT370	
16	373	Street Lighting & Signal Systems	PLT373	
17		Other	DISTPIS	
18		Total All Distribution Depreciation Expense		
19		General Plant Depreciation Expense	GENLPIS	
20		Total Depreciation Expense		
21		Taxes Other Than Income Taxes		
22	408	Property Tax - Production	DPROD	
23	408	Property Tax - Transmission	DTNEHV	
24	408	Property Tax - Transmission	DTEHV	
25	408	Property Tax - Distribution	DISTPIS	
26	408	Property Tax - General	GENLPIS	
27	408	Payroll	TOTPIS	
28	408	Medical and Dental	TOTPIS	
29	408	Other	TOTPIS	
30		Total Taxes Other Than Income Taxes		
31		Interest on Customer Deposits		
32	431	Customer Deposit Interest Expense	DISTPIS	
33		Income Taxes		
34	409	Current Income Tax - State & Federal	TOTPIS	
35		Total Operating Expense - Excluding Income Taxes		
36		Total Operating Expense - Including Taxes		

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCOUNT	FERC ACCOUNT DESCRIPTION	Allocation	LARGE POWER SERVICE DEMAND	LARGE POWER SERVICE ENERGY	LARGE POWER SERVICE CUSTOMER	LIGHTING DEMAND	LIGHTING ENERGY	LIGHTING CUSTOMER
1		**Steam Power Generation Expense**							
2	500	Operation Supervision & Engineering	DPROD	$0	$0	$0	$0	$0	$0
3	501	501-FUEL PPFAC ELIGIBLE	EFUEL	0	0	0	0	0	0
4	502	Steam Expenses	DPROD	0	0	0	0	0	0
5	505	Electric Expenses	DPROD	0	0	0	0	0	0
6	506	Miscellaneous Steam Power Expenses	DPROD	0	0	0	0	0	0
7	507	Rents	DPROD	0	0	0	0	0	0
8	510	Maintenance Supervision & Engineering	DPROD	0	0	0	0	0	0
9	511	Maintenance of Structures	DPROD	0	0	0	0	0	0
10	512	Maintenance of Boiler Plant	DPROD	0	0	0	0	0	0
11	513	Maintenance of Electric Plant	DPROD	0	0	0	0	0	0
12	514	Maintenance Miscellaneous Steam Plant	DPROD	0	0	0	0	0	0
13	411	FAS 143 Accretion Expense	DPROD	0	0	0	0	0	0
14	412	Loss from Disposition of Utility Plant	DPROD	0	0	0	0	0	0
15		**Total Steam Power Generation Expense**		$0	$0	$0	$0	$0	$0
16		**Other Power Generation Expense**							
17	546	Operation Supervision & Engineering	DPROD	$144,145	$0	$0	$5,541	$0	$0
18	547	PPFAC - Fuel	EFUEL	0	299,177	0	0	2,651	0
19	548 & 549	Generation Exp & Misc Other Power Generation	DPROD	28,322	0	0	1,089	0	0
20	550	Rents	DPROD	0	0	0	0	0	0
21	551	Maintenance Supervision & Engineering	DPROD	276	0	0	11	0	0
22	552-554	Maintenance Structures, Generating, Other	DPROD	58,599	0	0	2,253	0	0
23	407	Regulatory Asset Amortization	DPROD	131,206	0	0	5,043	0	0
24		Total Other Power Generation Expense		$362,547	$299,177	$0	$13,936	$2,651	$0
25		**Total Production Expense**		$362,547	$299,177	$0	$13,936	$2,651	$0
26		**Other Power Supply Expense**							
27		PPFAC - Purchased Power							
28	555	PPFAC - DEMAND	EPROD	$0	$0	$0	$0	$0	$0
29	555	PPFAC - ENERGY	EFUEL	0	3,398,027	0	0	30,105	0
30		TOTAL PURCHASED POWER		$0	$3,398,027	$0	$0	$30,105	$0
31	556	System Control and Load Dispatching	DPROD	$0	$0	$0	$0	$0	$0
32	557	Other Expenses and Accretion Expense	DPROD	38,792	-	-	1,491	-	-
33		**Total Power Supply Expense**		$38,792	$3,398,027	$0	$1,491	$30,105	$0
34	565	Trans of Electricity by Others - PPFAC Eligible	EFUEL	$0	$486,462	$0	$0	$4,310	$0
35	565	Trans of Electricity by Others - PPFAC Non-Eligible	DTRAN	615,035	0	0	23,642	0	0
36		**Total Transmission Plant**		$615,035	$486,462	$0	$23,642	$4,310	$0

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCOUNT	FERC ACCOUNT DESCRIPTION	Allocation	LARGE POWER SERVICE DEMAND	LARGE POWER SERVICE ENERGY	LARGE POWER SERVICE CUSTOMER	LIGHTING DEMAND	LIGHTING ENERGY	LIGHTING CUSTOMER
1		Distribution Plant							
2	580	Operation Supervision & Engineering	LAB58189	$0	$0	$0	$456	$0	$245
3	581	Load Dispatching	DISTPIS	0	0	0	19,250	0	0
4	582	Station Expenses	DISTPIS	0	0	0	1,545	0	0
5	583	Overhead Line Expenses	OHDIST	0	0	0	593	0	319
6	584	Underground Line Expenses	UGDIST	0	0	0	0	0	521
7	585	Street Lighting & Signal System Expenses	DDISTLTG	0	0	0	0	0	0
8	586	Meter Expenses	CMETERS	0	0	894	0	0	0
9	587	Customer Installations Expense	CMETERS	0	0	95	0	0	0
10	588	Miscellaneous Distribution Expenses	DISTPIS	0	0	0	509	0	763
11	589	Rents	DISTPIS	0	0	0	596	0	0
12	590	Maintenance Supervision & Engineering	LAB59198	0	0	0	0	0	0
13	591	Maintenance of Structures	DISTPIS	0	0	0	0	0	0
14	592	Maintenance of Station Equipment	DISTPIS	0	0	0	20,230	0	0
15	593	Maintenance of Overhead Lines	OHDIST	0	0	0	645	0	347
16	594	Maintenance of Underground Lines	UGDIST	0	0	0	0	0	172
17	595	Maintenance of Line Transformers	PLT368	0	0	0	62	0	93
18	596	Maintenance of Street Lighting & Signal Systems	DDISTLTG	0	0	0	27,094	0	0
19	597	Maintenance of Meters	CMETERS	0	0	3	0	0	0
20	598	Maintenance of Miscellaneous Distribution Plant	DISTPIS	0	0	0	171	0	9
21	407	Regulatory Asset Amortization	DISTPIS	0	0	0	0	0	0
22		Total Distribution Plant		$0	$0	$992	$71,151	$0	$2,471
23		Customer Account Expense							
24	901&907	Supervision	CSUPV	$0	$0	$15	$0	$0	$8,861
24	902	Meter Reading Expenses	CREAD	0	0	28	0	0	0
25	903	Customer Records & Collection Expenses	CBILLCOL	0	0	121	0	0	72,533
26	904	Uncollectible Accounts	EUNCOL	23,172	0	0	3,673	0	0
27	905	Customer Accounts Expenses Supervision	LAB900	0	0	(0)	0	0	(64)
28	908	Customer Assistance Expenses	CCUSINFO	0	0	5	0	0	3,040
29	909	Informational and Instructional Advertising Expenses	CCUSINFO	0	0	17	0	0	10,235
30	910	Miscellaneous Customer Service & Informational Expenses	CCUSINFO	0	0	0	0	0	63
31		Total Customer Account Expense		$23,172	$0	$187	$3,673	$0	$94,668
32		Total Operation and Maintenance Expense Excluding Fuel & Power Supply Expense & A&G		$1,000,754	$486,462	$1,178	$112,402	$4,310	$97,139
33	920-935	Administrative and General Expense	OMXGENL	$203,066	$0	$522	$22,808	$0	$42,995
34		Total Operation and Maintenance Expense		$1,242,612	$4,183,666	$1,700	$136,701	$37,065	$140,134

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCOUNT	FERC ACCOUNT DESCRIPTION	Allocation	LARGE POWER SERVICE DEMAND	LARGE POWER SERVICE ENERGY	LARGE POWER SERVICE CUSTOMER	LIGHTING DEMAND	LIGHTING ENERGY	LIGHTING CUSTOMER
		Depreciation and Amortization							
1	301-303	Total Intangible Plant Depreciation Expense	PISXGENL	$25,758	$0	$34	$16,006	$0	$812
2	500-547	Production Depreciation Expense	DPROD	$207,931	$0	$0	$7,993	$0	$0
3		Transmission NonEHV	DTNEHV	$0	$0	$0	$0	$0	$0
4		Transmission EHV	DTEHV	0	0	0	0	0	0
5		Total Transmission Depreciation Expense		$0	$0	$0	$0	$0	$0
		Distribution Plant Depreciation Expense							
6	360	Land & Rights	PLT360	$0	$0	$0	$2	$0	$0
7	361	Structures & Improvements	PLT361	0	0	0	144	0	0
8	362	Station Equipment	PLT362	0	0	0	1,536	0	0
9	364	Poles, Towers, & Fixtures	PLT364	0	0	0	439	0	658
10	365	Overhead Conductors & Devices	PLT365	0	0	0	804	0	433
11	366	Underground Conduit	PLT366	0	0	0	0	0	355
12	367	Underground Conductors & Devices	PLT367	0	0	0	597	0	322
13	368	Line Transformers	PLT368	0	0	0	859	0	1,288
14	369	Services	PLT369	0	0	7	0	0	0
15	370	Meters	PLT370	0	0	273	0	0	0
16	373	Street Lighting & Signal Systems	PLT373	0	0	0	54,913	0	0
17		Other	DISTPIS	0	0	0	0	0	0
18		Total All Distribution Depreciation Expense		$0	$0	$280	$59,293	$0	$3,055
19		General Plant Depreciation Expense	GENLPIS	$20,455	$0	$27	$12,710	$0	$645
20		Total Depreciation Expense		$254,144	$0	$340	$96,002	$0	$4,513
21		Taxes Other Than Income Taxes							
22	408	Property Tax - Production	DPROD	$61,153	$0	$0	$2,351	$0	$0
23	408	Property Tax - Transmission	DTNEHV	0	0	0	0	0	0
24	408	Property Tax - Transmission	DTEHV	0	0	0	0	0	0
25	408	Property Tax - Distribution	DISTPIS	0	0	110	49,030	0	2,653
26	408	Property Tax - General	GENLPIS	3,285	0	4	2,041	0	104
27	408	Payroll	TOTPIS	5,061	0	7	3,145	0	160
28	408	Medical and Dental	TOTPIS	1,165	0	2	724	0	37
29	408	Other	TOTPIS	221	0	0	137	0	7
30		Total Taxes Other Than Income Taxes		$70,884	$0	$123	$57,428	$0	$2,960
31		Interest on Customer Deposits							
32	431	Customer Deposit Interest Expense	DISTPIS	$0	$0	$0	$0	$0	$0
33		Income Taxes							
34	409	Current Income Tax - State & Federal	TOTPIS	$18,105	$0	$24	$11,250	$0	$571
35		Total Operating Expense - Excluding Income Taxes		$1,567,640	$4,183,666	$2,163	$290,131	$37,065	$147,606
36		Total Operating Expense - Including Taxes		$1,585,744	$4,183,666	$2,187	$301,381	$37,065	$148,177

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - DISTRIBUTION OF RATE BASE BY FUNCTION
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCT.	FERC ACCOUNT DESCRIPTION	TOTAL COMPANY	DEMAND	ENERGY	CUSTOMER	DIRECT ASSIGNMENT	DEMAND: PRODUCTION	DEMAND: TRANSMISSION EXPENSE	DEMAND: DISTRIBUTION PRIMARY
1	301-303	Total Intangible Plant	$7,646,054	$5,325,775	$0	$2,320,279	$0	$2,533,338	$0	$2,365,117
2		Total Steam Production								
3	310	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0
4	311	Structures & Improvements	0	0	0	0	0	0	0	0
5	312	Boiler Plant Equipment	0	0	0	0	0	0	0	0
6	313	Engines & Engine-Driven Generators	0	0	0	0	0	0	0	0
7	314	Turbogenerator Units	0	0	0	0	0	0	0	0
8	315	Accessory Electric Equipment	0	0	0	0	0	0	0	0
9	316	Miscellaneous Power Plant Equipment	0	0	0	0	0	0	0	0
10	114	San Juan & Irvington Acquistion Adjustment	0	0	0	0	0	0	0	0
11	102	Electric Plant Purchased or Sold	0	0	0	0	0	0	0	0
12		Total Steam Production	$0	$0	$0	$0	$0	$0	$0	$0
13		Other Production Plant								
14	340	Land & Land Rights	($125,742)	($125,742)	$0	$0	$0	($125,742)	$0	$0
15	341	Structures & Improvements	6,849,569	6,849,569	0	0	0	6,849,569	0	0
16	342	Fuel Holders, Producers, & Accessories	2,826,837	2,826,837	0	0	0	2,826,837	0	0
17	343	Prime Movers	62,410,318	62,410,318	0	0	0	62,410,318	0	0
18	344	Generators	73,947,185	73,947,185	0	0	0	73,947,185	0	0
19	345	Accessory Electric Equipment	13,563,682	13,563,682	0	0	0	13,563,682	0	0
20	346&347	Miscellaneous Power Plant Equipment	14,388,420	14,388,420	0	0	0	14,388,420	0	0
21		Total Other Production Plant	$173,860,268	$173,860,268	$0	$0	$0	$173,860,268	$0	$0
22		Total Production Plant	$173,860,268	$173,860,268	$0	$0	$0	$173,860,268	$0	$0
23	350-359	Transmission	$0	$0	$0	$0	$0	$0	$0	$0
24	XXX	Intentionally Blank	0	0	0	0	0	0	0	0
25		Total Transmission Plant	$0	$0	$0	$0	$0	$0	$0	$0
26		Distribution Plant								
27	360	Land & Rights	$837,790	$837,790	$0	$0	$0	$0	$0	$837,790
28	361	Structures & Improvements	6,085,135	6,085,135	0	0	0	0	0	6,085,135
29	362	Station Equipment	58,174,288	58,174,288	0	0	0	0	0	58,174,288
30	364	Poles, Towers, & Fixtures	74,467,314	29,786,926	0	44,680,388	0	0	0	29,786,926
31	365	Overhead Conductors & Devices	63,488,578	41,267,575	0	22,221,002	0	0	0	41,267,575
32	366	Underground Conduit	18,173,564	0	0	18,173,564	0	0	0	0
33	367	Underground Conductors & Devices	39,003,990	25,352,594	0	13,651,397	0	0	0	0
34	368	Line Transformers	65,409,315	26,163,726	0	39,245,589	0	0	0	26,163,726
35	369	Services	13,979,252	0	0	13,979,252	0	0	0	0
36	370	Meters	7,287,096	0	0	7,287,096	0	0	0	0
37	373	Street Lighting & Signal Systems	3,973,928	3,973,928	0	0	0	0	0	0
38	374	Asset Retirement Obligation	0	0	0	0	0	0	0	0
39		Total Distribution Plant	$350,880,250	$191,641,961	$0	$159,238,288	$0	$0	$0	$162,315,440
40		Total Plant Excluding Intang. & General Plant	$524,740,517	$365,502,229	$0	$159,238,288	$0	$173,860,268	$0	$162,315,440
41	389-398	General Plant	$37,158,791	25,882,547	0	11,276,244	0	12,311,680	0	11,494,149
42		TOTAL PLANT IN SERVICE	$569,545,363	$396,710,551	$0	$172,834,812	$0	$188,705,286	$0	$176,174,705

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - DISTRIBUTION OF RATE BASE BY FUNCTION
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCT.	FERC ACCOUNT DESCRIPTION	TOTAL COMPANY	DEMAND	ENERGY	CUSTOMER	DIRECT ASSIGNMENT	DEMAND PRODUCTION	DEMAND TRANSMISSION EXPENSE	DEMAND DISTRIBUTION PRIMARY
		Less: Accumulated Depreciation								
1		Total Intangible Plant AD	$2,493,520	$1,736,834	$0	$756,686	$0	$826,168	$0	$771,308
2		Production Plant	$0	$0	$0	$0	$0	$0	$0	$0
3		Other Production Plant	37,652,975	37,652,975	0	0	0	37,652,975	0	0
4		Total Production Plant AD	$37,652,975	$37,652,975	$0	$0	$0	$37,652,975	$0	$0
5		Transmission Non-EHV (138 KV & below) AD	0	0	0	0	0	0	0	0
6		Transmission EHV (345 KV & above) AD	0	0	0	0	0	0	0	0
7		Total Transmission Plant	$0	$0	$0	$0	$0	$0	$0	$0
8		Distribution Plant AD								
9	360	Land & Rights	$58,400	$58,400	$0	$0	$0	$0	$0	$58,400
10	361	Structures & Improvements	2,360,634	2,360,634	0	0	0	0	0	2,360,634
11	362	Station Equipment	24,187,350	24,187,350	0	0	0	0	0	24,187,350
12	364	Poles, Towers, & Fixtures	59,419,065	23,767,626	0	35,651,439	0	0	0	23,767,626
13	365	Overhead Conductors & Devices	40,236,966	26,154,028	0	14,082,938	0	0	0	26,154,028
14	366	Underground Conduit	8,289,171	0	0	8,289,171	0	0	0	0
15	367	Underground Conductors & Devices	20,316,091	13,205,459	0	7,110,632	0	0	0	0
16	368	Line Transformers	39,298,056	15,719,222	0	23,578,834	0	0	0	15,719,222
17	369	Services	8,208,556	0	0	8,208,556	0	0	0	0
18	370	Meters	(1,813,849)	0	0	(1,813,849)	0	0	0	0
19	373	Street Lighting & Signal Systems	2,952,870	2,952,870	0	0	0	0	0	0
20	374	Asset Retirement Obligation	0	0	0	0	0	0	0	0
21		Total Distribution AD	$203,513,309	$108,405,589	$0	$95,107,720	$0	$0	$0	$92,247,260
22		General Plant Accumulated Depreciation	$17,203,281	$11,982,756	$0	$5,220,525	$0	$5,699,897	$0	$5,321,408
23		TOTAL ACCUMULATED DEPRECIATION	$260,863,085	$159,778,154	$0	$101,084,931	$0	$44,179,041	$0	$98,339,976
24		Working Capital								
25	n/a	Cash Working Capital	($5,198,426)	($3,620,906)	$0	($1,577,520)	$0	($1,722,375)	$0	($1,608,004)
26	151, 152	Fuel Inventory	276,430	276,430	0	0	0	276,430	0	0
27	154, 163	Materials & Supplies	11,353,152	7,907,913	0	3,445,239	0	3,761,596	0	3,511,815
28	165	Prepayments	743,554	517,914	0	225,640	0	246,359	0	230,000
29		Total Working Capital	$7,174,709	$5,081,350	$0	$2,093,359	$0	$2,562,010	$0	$2,133,811
30		Less: Customer Contributions								
31	252	Customer Advances for Construction	($3,833,219)	($3,833,219)	$0	$0	$0	$0	$0	$0
32	235	Customer Deposits	(4,427,886)	(4,427,886)	0	0	0	0	0	0
33	230&253	Deferred Credits - Asset Retirement	(421,645)	(230,292)	0	(191,353)	0	0	0	(195,051)
34		Total Customer Contributions	($8,682,750)	($8,491,397)	$0	($191,353)	$0	$0	$0	($195,051)
35		Other Rate Base								
36	105.0	Plant Held for Future Use - Transmission Plant (Non-EHV)	$0	$0	$0	$0	$0	$0	$0	$0
37	182.3	Regulatory Assets	0	0	0	0	0	0	0	0
38	254	Regulatory Liabilities	0	0	0	0	0	0	0	0
39		Total Other Rate Base	$0	$0	$0	$0	$0	$0	$0	$0
40		Less: Accumulated Deferred Taxes (ADIT)								
41	190	ADIT	$15,091,263	$10,511,653	$0	$4,579,610	$0	$5,000,130	$0	$4,668,107
42	282	ADIT - Other Property	(50,252,371)	(35,002,735)	0	(15,249,635)	0	(16,649,926)	0	(15,544,322)
43		Total Accumulated Deferred Taxes	($35,161,108)	($24,491,082)	$0	($10,670,025)	$0	($11,649,795)	$0	($10,876,215)
44		TOTAL RATE BASE	$272,013,129	$209,031,267	$0	$62,981,861	$0	$135,438,460	$0	$68,897,275

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - DISTRIBUTION OF RATE BASE BY FUNCTION
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCT.	FERC ACCOUNT DESCRIPTION	TOTAL COMPANY	DISTRIBUTION SECONDARY	ENERGY FUEL	ENERGY CUSTOMER	ENERGY UNCOLLECTIBLES	CUSTOMER Customer Delivery	CUSTOMER METER	CUSTOMER BILLING & COLLECTIONS	CUSTOMER METER READING
1	301-303	Total Intangible Plant	$7,646,054	$427,320	$0	$0	$0	$2,214,098	$106,181	$0	$0
2		Total Steam Production									
3	310	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0
4	311	Structures & Improvements	0	0	0	0	0	0	0	0	0
5	312	Boiler Plant Equipment	0	0	0	0	0	0	0	0	0
6	313	Engines & Engine-Driven Generators	0	0	0	0	0	0	0	0	0
7	314	Turbogenerator Units	0	0	0	0	0	0	0	0	0
8	315	Accessory Electric Equipment	0	0	0	0	0	0	0	0	0
9	316	Miscellaneous Power Plant Equipment	0	0	0	0	0	0	0	0	0
10	114	San Juan & Irvington Acquistion Adjustment	0	0	0	0	0	0	0	0	0
11	102	Electric Plant Purchased or Sold	0	0	0	0	0	0	0	0	0
12		Total Steam Production	$0	$0	$0	$0	$0	$0	$0	$0	$0
13		Other Production Plant									
14	340	Land & Land Rights	($125,742)	$0	$0	$0	$0	$0	$0	$0	$0
15	341	Structures & Improvements	6,849,569	0	0	0	0	0	0	0	0
16	342	Fuel Holders, Producers, & Accessories	2,826,837	0	0	0	0	0	0	0	0
17	343	Prime Movers	62,410,318	0	0	0	0	0	0	0	0
18	344	Generators	73,947,185	0	0	0	0	0	0	0	0
19	345	Accessory Electric Equipment	13,563,682	0	0	0	0	0	0	0	0
20	346&347	Miscellaneous Power Plant Equipment	14,388,420	0	0	0	0	0	0	0	0
21		Total Other Production Plant	$173,860,268	$0	$0	$0	$0	$0	$0	$0	$0
22		Total Production Plant	$173,860,268	$0	$0	$0	$0	$0	$0	$0	$0
23	350-359	Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	XXX	Intentionally Blank	0	0	0	0	0	0	0	0	0
25		Total Transmission Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0
26		Distribution Plant									
27	360	Land & Rights	$837,790	$0	$0	$0	$0	$0	$0	$0	$0
28	361	Structures & Improvements	6,085,135	0	0	0	0	0	0	0	0
29	362	Station Equipment	58,174,288	0	0	0	0	0	0	0	0
30	364	Poles, Towers, & Fixtures	74,467,314	0	0	0	0	44,680,388	0	0	0
31	365	Overhead Conductors & Devices	63,488,578	0	0	0	0	22,221,002	0	0	0
32	366	Underground Conduit	18,173,564	0	0	0	0	18,173,564	0	0	0
33	367	Underground Conductors & Devices	39,003,990	25,352,594	0	0	0	13,651,397	0	0	0
34	368	Line Transformers	65,409,315	0	0	0	0	39,245,589	0	0	0
35	369	Services	13,979,252	0	0	0	0	13,979,252	0	0	0
36	370	Meters	7,287,096	0	0	0	0	0	7,287,096	0	0
37	373	Street Lighting & Signal Systems	3,973,928	3,973,928	0	0	0	0	0	0	0
38	374	Asset Retirement Obligation	0	0	0	0	0	0	0	0	0
39		Total Distribution Plant	$350,880,250	$29,326,522	$0	$0	$0	$151,951,192	$7,287,096	$0	$0
40		Total Plant Excluding Intang. & General Plant	$524,740,517	$29,326,522	$0	$0	$0	$151,951,192	$7,287,096	$0	$0
41	389-398	General Plant	$37,158,791	2,076,718	0	0	0	10,760,218	516,026	0	0
42		TOTAL PLANT IN SERVICE	$569,545,363	$31,830,560	$0	$0	$0	$164,925,508	$7,909,303	$0	$0

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - DISTRIBUTION OF RATE BASE BY FUNCTION
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCT.	FERC ACCOUNT DESCRIPTION	TOTAL COMPANY	DISTRIBUTION SECONDARY	ENERGY: FUEL	ENERGY: CUSTOMER	ENERGY: UNCOLLECTIBLES	CUSTOMER: Customer Delivery	CUSTOMER: METER	CUSTOMER: BILLING & COLLECTIONS	CUSTOMER: METER READING
		Less: Accumulated Depreciation									
1		Total Intangible Plant AD	$2,493,520	$139,357	$0	$0	$0	$722,058	$34,628	$0	$0
2		Production Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0
3		Other Production Plant	37,652,975	0	0	0	0	0	0	0	0
4		Total Production Plant AD	$37,652,975	$0	$0	$0	$0	$0	$0	$0	$0
5		Transmission Non-EHV (138 KV & below) AD	0	0	0	0	0	0	0	0	0
6		Transmission EHV (345 KV & above) AD	0	0	0	0	0	0	0	0	0
7		Total Transmission Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0
8		Distribution Plant AD									
9	360	Land & Rights	$58,400	$0	$0	$0	$0	$0	$0	$0	$0
10	361	Structures & Improvements	2,360,634	0	0	0	0	0	0	0	0
11	362	Station Equipment	24,187,350	0	0	0	0	0	0	0	0
12	364	Poles, Towers, & Fixtures	59,419,065	0	0	0	0	35,651,439	0	0	0
13	365	Overhead Conductors & Devices	40,236,966	0	0	0	0	14,082,938	0	0	0
14	366	Underground Conduit	8,289,171	0	0	0	0	8,289,171	0	0	0
15	367	Underground Conductors & Devices	20,316,091	13,205,459	0	0	0	7,110,632	0	0	0
16	368	Line Transformers	39,298,056	0	0	0	0	23,578,834	0	0	0
17	369	Services	8,208,556	0	0	0	0	8,208,556	0	0	0
18	370	Meters	(1,813,849)	0	0	0	0	0	(1,813,849)	0	0
19	373	Street Lighting & Signal Systems	2,952,870	2,952,870	0	0	0	0	0	0	0
20	374	Asset Retirement Obligation	0	0	0	0	0	0	0	0	0
21		Total Distribution AD	$203,513,309	$16,158,329	$0	$0	$0	$96,921,569	($1,813,849)	$0	$0
22		General Plant Accumulated Depreciation	$17,203,281	$961,451	$0	$0	$0	$4,981,622	$238,903	$0	$0
23		TOTAL ACCUMULATED DEPRECIATION	$260,863,085	$17,259,137	$0	$0	$0	$102,625,250	($1,540,319)	$0	$0
24		Working Capital									
25	n/a	Cash Working Capital	($5,198,426)	($290,528)	$0	$0	$0	($1,505,329)	($72,191)	$0	$0
26	151, 152	Fuel Inventory	276,430	0	0	0	0	0	0	0	0
27	154, 163	Materials & Supplies	11,353,152	634,501	0	0	0	3,287,577	157,662	0	0
28	165	Prepayments	743,554	41,555	0	0	0	215,314	10,326	0	0
29		Total Working Capital	$7,174,709	$385,529	$0	$0	$0	$1,997,562	$95,797	$0	$0
30		Less: Customer Contributions									
31	252	Customer Advances for Construction	($3,833,219)	($3,833,219)	$0	$0	$0	$0	$0	$0	$0
32	235	Customer Deposits	(4,427,886)	(4,427,886)	0	0	0	0	0	0	0
33	230&253	Deferred Credits - Asset Retirement	(421,645)	(35,241)	0	0	0	(182,596)	(8,757)	0	0
34		Total Customer Contributions	($8,682,750)	($8,296,346)	$0	$0	$0	($182,596)	($8,757)	$0	$0
35		Other Rate Base									
36	105.0	Plant Held for Future Use - Transmission Plant (Non-EHV)	$0	$0	$0	$0	$0	$0	$0	$0	$0
37	182.3	Regulatory Assets	0	0	0	0	0	0	0	0	0
38	254	Regulatory Liabilities	0	0	0	0	0	0	0	0	0
39		Total Other Rate Base	$0	$0	$0	$0	$0	$0	$0	$0	$0
40		Less: Accumulated Deferred Taxes (ADIT)									
41	190	ADIT	$15,091,263	$843,415	$0	$0	$0	$4,370,037	$209,573	$0	$0
42	282	ADIT - Other Property	(50,252,371)	(2,808,488)	0	0	0	(14,551,778)	(697,857)	0	0
43		Total Accumulated Deferred Taxes	($35,161,108)	($1,965,072)	$0	$0	$0	($10,181,741)	($488,284)	$0	$0
44		TOTAL RATE BASE	$272,013,129	$4,695,533	$0	$0	$0	$53,933,483	$9,048,378	$0	$0

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - DISTRIBUTION OF EXPENSE BY FUNCTION
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCT.	FERC ACCOUNT DESCRIPTION	TOTAL COMPANY	DEMAND	ENERGY	CUSTOMER	DIRECT ASSIGNMENT	DEMAND PRODUCTION	DEMAND TRANSMISSION EXPENSE	DEMAND Blank
		Steam Power Generation Expense								
1	500	Operation Supervision & Engineering	$0	$0	$0	$0	$0	$0	$0	$0
2	501	PPFAC - FUEL	0	0	0	0	0	0	0	0
3	502	Steam Expenses	0	0	0	0	0	0	0	0
4	505	Electric Expenses	0	0	0	0	0	0	0	0
5	506	Miscellaneous Steam Power Expenses	0	0	0	0	0	0	0	0
6	507	Rents	0	0	0	0	0	0	0	0
7	510	Maintenance Supervision & Engineering	0	0	0	0	0	0	0	0
8	511	Maintenance of Structures	0	0	0	0	0	0	0	0
9	512	Maintenance of Boiler Plant	0	0	0	0	0	0	0	0
10	513	Maintenance of Electric Plant	0	0	0	0	0	0	0	0
11	514	Maintenance Miscellaneous Steam Plant	0	0	0	0	0	0	0	0
12	411	FAS 143 Accretion Expense	0	0	0	0	0	0	0	0
13	412	Loss from Disposition of Utility Plant	0	0	0	0	0	0	0	0
14		**Total Steam Power Generation Expense**	$0	$0	$0	$0	$0	$0	$0	$0
15		**Other Power Generation Expense**								
16	546	Operation Supervision & Engineering	$3,405,721	$3,405,721	$0	$0	$0	$3,405,721	$0	$0
17	547	PPFAC - Fuel	5,543,690	0	5,543,690	0	0	0	0	0
18	548 & 549	Generation Exp & Misc Other Power Generation	669,155	669,155	0	0	0	669,155	0	0
19	550	Rents	0	0	0	0	0	0	0	0
20	551	Maintenance Supervision & Engineering	6,512	6,512	0	0	0	6,512	0	0
21	552-554	Maintenance Structures, Generating, Other	1,384,519	1,384,519	0	0	0	1,384,519	0	0
22	407	Regulatory Asset Amortization	3,100,000	3,100,000	0	0	0	3,100,000	0	0
23		Total Other Power Generation Expense	$14,109,597	$8,565,907	$5,543,690	$0	$0	$8,565,907	$0	$0
24		**Total Production Expense**	$14,109,597	$8,565,907	$5,543,690	$0	$0	$8,565,907	$0	$0
25		**Other Power Supply Expense**								
26		PPFAC - Purchased Power								
27	555	PPFAC - DEMAND	$0	$0	$0	$0	$0	$0	$0	$0
28	555	PPFAC - ENERGY	62,964,670	0	62,964,670	0	0	0	0	0
29		TOTAL PURCHASED POWER	62,964,670	0	62,964,670	0	0	0	0	0
30	556	System Control and Load Dispatching	0	0	0	0	$0	$0	$0	$0
31	557	Other Expenses and Accretion Expense	916,543	916,543	0	0	0	$916,543	0	0
32		**Total Power Supply Expense**	$63,881,212	$916,543	$62,964,670	$0	$0	$916,543	$0	$0
33	565	Trans of Electricity by Others - PPFAC Eligible	$9,014,026	$0	$9,014,026	$0	$0	$0	$0	$0
34	565	Trans of Electricity by Others - PPFAC Non-Eligible	14,531,456	14,531,456	0	0	0	0	14,531,456	0
35		**Total Transmission Plant**	$23,545,482	$14,531,456	$9,014,026	$0	$0	$0	$14,531,456	$0

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - DISTRIBUTION OF EXPENSE BY FUNCTION
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCT.	FERC ACCOUNT DESCRIPTION	TOTAL COMPANY	DEMAND	ENERGY	CUSTOMER	DIRECT ASSIGNMENT	DEMAND PRODUCTION	DEMAND TRANSMISSION EXPENSE	DEMAND Blank
		Distribution Plant								
1	580	Operation Supervision & Engineering	$416,745	$270,884	$0	$145,861	$0	$0	$0	$0
2	581	Load Dispatching	860,035	860,035	0	$0	0	0	0	0
3	582	Station Expenses	69,023	69,023	0	$0	0	0	0	0
4	583	Overhead Line Expenses	542,487	352,616	0	$189,870	0	0	0	0
5	584	Underground Line Expenses	309,851	0	0	$309,851	0	0	0	0
6	585	Street Lighting & Signal System Expenses	0	0	0	$0	0	0	0	0
7	586	Meter Expenses	721,222	0	0	$721,222	0	0	0	0
8	587	Customer Installations Expense	76,287	0	0	$76,287	0	0	0	0
9	588	Miscellaneous Distribution Expenses	756,371	302,548	0	453,823	0	0	0	0
10	589	Rents	26,605	26,605	0	0	0	0	0	0
11	590	Maintenance Supervision & Engineering	25	16	0	9	0	0	0	0
12	591	Maintenance of Structures	0	0	0	0	0	0	0	0
13	592	Maintenance of Station Equipment	903,797	903,797	0	0	0	0	0	0
14	593	Maintenance of Overhead Lines	589,548	383,206	0	206,342	0	0	0	0
15	594	Maintenance of Underground Lines	102,120	0	0	102,120	0	0	0	0
16	595	Maintenance of Line Transformers	92,619	37,047	0	55,571	0	0	0	0
17	596	Maintenance of Street Lighting & Signal Systems	27,094	27,094	0	0	0	0	0	0
18	597	Maintenance of Meters	2,080	0	0	2,080	0	0	0	0
19	598	Maintenance of Miscellaneous Distribution Plant	14,028	5,611	0	8,417	0	0	0	0
20	407	Regulatory Asset Amortization	0	0	0	0	0	0	0	0
21		Other	0	0	0	0	0	0	0	0
22		Total Distribution Plant	$5,509,935	$3,238,482	$0	$2,271,452	$0	$0	$0	$0
		Customer Account Expense								
23	901	Supervision	$353,018	$0	$0	$353,018		$0	$0	$0
24	902	Meter Reading Expenses	651,708	0	0	651,708	0	0	0	0
25	903	Customer Records & Collection Expenses	2,889,804	0	0	2,889,804	0	0	0	0
26	904	Uncollectible Accounts	505,677	505,677	0	0	0	0	0	0
27	905	Miscellaneous Customer Accounts Expenses	(2,533)	0	0	(2,533)	0	0	0	0
28	908	Customer Assistance Expenses	121,102	0	0	121,102	0	0	0	0
29	909	Informational and Instructional Advertising Expenses	407,788	0	0	407,788	0	0	0	0
30	910	Miscellaneous Customer Service & Informational Expenses	2,496	0	0	2,496	0	0	0	0
31		Total Customer Account Expense	$4,929,060	$505,677	$0	$4,423,384	$0	$0	$0	$0
32		Total Operation and Maintenance Expense Excluding Fuel & Power Supply Expense & A&G	$42,550,384	$26,841,522	$9,014,026	$6,694,836	$0	$8,565,907	$14,531,456	$0
33	920-935	Administrative and General Expense	$8,409,208	5,446,906	0	2,962,302	$0	$3,790,206	$0	$0
34		Total Operation and Maintenance Expense	$120,384,494	$33,204,970	$77,522,385	$9,657,138	$0	$13,272,656	$14,531,456	$0

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - DISTRIBUTION OF EXPENSE BY FUNCTION
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCT.	FERC ACCOUNT DESCRIPTION	TOTAL COMPANY	DEMAND	ENERGY	CUSTOMER	DIRECT ASSIGNMENT	DEMAND PRODUCTION	DEMAND TRANSMISSION EXPENSE	DEMAND Blank
		Depreciation and Amortization								
1	301-303	Total Intangible Plant Depreciation Expense	$1,836,827	$1,279,421	$0	$557,405	$0	$608,589	$0	$0
2	500-547	Production Depreciation Expense	$4,912,792	$4,912,792	$0	$0	$0	$4,912,792	$0	$0
3		Transmission EXPENSE	$0	$0	$0	$0	$0	$0	$0	$0
4		Transmission EXPENSE	0	0	0	0	0	0	0	0
5		Total Transmission Depreciation Expense	$0	$0	$0	$0	$0	$0	$0	$0
6		Distribution Plant Depreciation Expense								
7	360	Land & Rights	$1,070	$1,070	$0	$0	$0	$0	$0	$0
8	361	Structures & Improvements	85,623	85,623	0	0	0	0	0	0
9	362	Station Equipment	913,346	913,346	0	0	0	0	0	0
10	364	Poles, Towers, & Fixtures	652,041	260,816	0	391,224	0	0	0	0
11	365	Overhead Conductors & Devices	734,953	477,720	0	257,234	0	0	0	0
12	366	Underground Conduit	211,032	0	0	211,032	0	0	0	0
13	367	Underground Conductors & Devices	546,264	355,072	0	191,192	0	0	0	0
14	368	Line Transformers	1,276,133	510,453	0	765,680	0	0	0	0
15	369	Services	155,540	0	0	155,540	0	0	0	0
16	370	Meters	220,357	0	0	220,357	0	0	0	0
17	373	Street Lighting & Signal Systems	54,913	54,913	0	0	0	0	0	0
18		Other	0	0	0	0	0	0	0	0
19		Total All Distribution Depreciation Expense	$4,851,273	$2,659,013	$0	$2,192,259	$0	$0	$0	$0
20		General Plant Depreciation Expense	1,458,632	1,015,994	0	442,638	0	483,283	0	0
21		Total Depreciation Expense	$13,059,523	$9,867,221	$0	$3,192,302	$0	$6,004,664	$0	$0
22		Taxes Other Than Income Taxes								
23	408	Property Tax - Production	$1,444,855	$1,444,855	$0	$0	$0	$1,444,855	$0	$0
24	408	Property Tax - Transmission	0	0	0	0	0	0	0	0
25	408	Property Tax - Transmission	0	0	0	0	0	0	0	0
26	408	Property Tax - Distribution	4,010,589	2,190,483	0	1,820,106	0	0	0	0
27	408	Property Tax - General	234,225	163,147	0	71,078	0	77,605	0	0
28	408	Payroll	360,900	251,381	0	109,519	0	119,575	0	0
29	408	Medical and Dental	83,077	57,867	0	25,211	0	27,526	0	0
30	408	Other	15,775	10,988	0	4,787	0	5,227	0	0
31		Total Taxes Other Than Income Taxes	$6,149,421	$4,118,720	$0	$2,030,701	$0	$1,674,788	$0	$0
32		Interest on Customer Deposits								
33	431	Customer Deposit Interest Expense	$7,440	$7,440	$0	$0	$0	$0	$0	$0
34		Income Taxes								
35	409	Current Income Tax - State & Federal	$1,291,053	$899,269	$0	$391,784	$0	$427,760	$0	$0
36		Total Operating Expense - Excluding Income Taxes	$139,600,878	$47,198,351	$77,522,385	$14,880,142	$0	$20,952,107	$14,531,456	$0
37		Total Operating Expense - Including Taxes	$140,891,931	$48,097,619	$77,522,385	$15,271,926	$0	$21,379,867	$14,531,456	$0

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - DISTRIBUTION OF EXPENSE BY FUNCTION
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCT.	FERC ACCOUNT DESCRIPTION	TOTAL COMPANY	DISTRIBUTION PRIMARY
		Steam Power Generation Expense		
1	500	Operation Supervision & Engineering	$0	$0
2	501	PPFAC - FUEL	0	0
3	502	Steam Expenses	0	0
4	505	Electric Expenses	0	0
5	506	Miscellaneous Steam Power Expenses	0	0
6	507	Rents	0	0
7	510	Maintenance Supervision & Engineering	0	0
8	511	Maintenance of Structures	0	0
9	512	Maintenance of Boiler Plant	0	0
10	513	Maintenance of Electric Plant	0	0
11	514	Maintenance Miscellaneous Steam Plant	0	0
12	411	FAS 143 Accretion Expense	0	0
13	412	Loss from Disposition of Utility Plant	0	0
14		**Total Steam Power Generation Expense**	$0	$0
15		**Other Power Generation Expense**		
16	546	Operation Supervision & Engineering	$3,405,721	$0
17	547	PPFAC - Fuel	5,543,690	0
18	548 & 549	Generation Exp & Misc Other Power Generation	669,155	0
19	550	Rents	0	0
20	551	Maintenance Supervision & Engineering	6,512	0
21	552-554	Maintenance Structures, Generating, Other	1,384,519	0
22	407	Regulatory Asset Amortization	3,100,000	0
23		Total Other Power Generation Expense	$14,109,597	$0
24		**Total Production Expense**	$14,109,597	$0
25		**Other Power Supply Expense**		
26		PPFAC - Purchased Power		
27	555	PPFAC - DEMAND	$0	$0
28	555	PPFAC - ENERGY	62,964,670	0
29		TOTAL PURCHASED POWER	62,964,670	0
30	556	System Control and Load Dispatching	0	$0
31	557	Other Expenses and Accretion Expense	916,543	0
32		**Total Power Supply Expense**	$63,881,212	$0
33	565	Trans of Electricity by Others - PPFAC Eligible	$9,014,026	$0
34	565	Trans of Electricity by Others - PPFAC Non-Eligible	14,531,456	0
35		**Total Transmission Plant**	$23,545,482	$0

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - DISTRIBUTION OF EXPENSE BY FUNCTION
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCT.	FERC ACCOUNT DESCRIPTION	TOTAL COMPANY	DISTRIBUTION PRIMARY
		Distribution Plant		
1	580	Operation Supervision & Engineering	$416,745	$270,884
2	581	Load Dispatching	860,035	860,035
3	582	Station Expenses	69,023	69,023
4	583	Overhead Line Expenses	542,487	352,616
5	584	Underground Line Expenses	309,851	0
6	585	Street Lighting & Signal System Expenses	0	0
7	586	Meter Expenses	721,222	0
8	587	Customer Installations Expense	76,287	0
9	588	Miscellaneous Distribution Expenses	756,371	302,548
10	589	Rents	26,605	26,605
11	590	Maintenance Supervision & Engineering	25	16
12	591	Maintenance of Structures	0	0
13	592	Maintenance of Station Equipment	903,797	903,797
14	593	Maintenance of Overhead Lines	589,548	383,206
15	594	Maintenance of Underground Lines	102,120	0
16	595	Maintenance of Line Transformers	92,619	37,047
17	596	Maintenance of Street Lighting & Signal Systems	27,094	0
18	597	Maintenance of Meters	2,080	0
19	598	Maintenance of Miscellaneous Distribution Plant	14,028	5,611
20	407	Regulatory Asset Amortization	0	0
21		Other	0	0
22		Total Distribution Plant	$5,509,935	$3,211,388
		Customer Account Expense		
23	901	Supervision	$353,018	$0
24	902	Meter Reading Expenses	651,708	0
25	903	Customer Records & Collection Expenses	2,889,804	0
26	904	Uncollectible Accounts	505,677	0
27	905	Miscellaneous Customer Accounts Expenses	(2,533)	0
28	908	Customer Assistance Expenses	121,102	0
29	909	Informational and Instructional Advertising Expenses	407,788	0
30	910	Miscellaneous Customer Service & Informational Expenses	2,496	0
31		Total Customer Account Expense	$4,929,060	$0
32		Total Operation and Maintenance Expense Excluding Fuel & Power Supply Expense & A&G	$42,550,384	$3,211,388
33	920-935	Administrative and General Expense	$8,409,208	$1,420,961
34		Total Operation and Maintenance Expense	$120,384,494	$4,632,350

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - DISTRIBUTION OF EXPENSE BY FUNCTION
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCT.	FERC ACCOUNT DESCRIPTION	TOTAL COMPANY	DISTRIBUTION PRIMARY
		Depreciation and Amortization		
1	301-303	Total Intangible Plant Depreciation Expense	$1,836,827	$568,177
2	500-547	Production Depreciation Expense	$4,912,792	$0
3		Transmission EXPENSE	$0	$0
4		Transmission EXPENSE	0	0
5		Total Transmission Depreciation Expense	$0	$0
6		Distribution Plant Depreciation Expense		
7	360	Land & Rights	$1,070	$1,070
8	361	Structures & Improvements	85,623	85,623
9	362	Station Equipment	913,346	913,346
10	364	Poles, Towers, & Fixtures	652,041	260,816
11	365	Overhead Conductors & Devices	734,953	477,720
12	366	Underground Conduit	211,032	0
13	367	Underground Conductors & Devices	546,264	0
14	368	Line Transformers	1,276,133	510,453
15	369	Services	155,540	0
16	370	Meters	220,357	0
17	373	Street Lighting & Signal Systems	54,913	0
18		Other	0	0
19		Total All Distribution Depreciation Expense	$4,851,273	$2,249,028
20		General Plant Depreciation Expense	1,458,632	451,192
21		Total Depreciation Expense	$13,059,523	$3,268,396
22		Taxes Other Than Income Taxes		
23	408	Property Tax - Production	$1,444,855	$0
24	408	Property Tax - Transmission	0	0
25	408	Property Tax - Transmission	0	0
26	408	Property Tax - Distribution	4,010,589	1,855,278
27	408	Property Tax - General	234,225	72,452
28	408	Payrolll	360,900	111,635
29	408	Medical and Dental	83,077	25,698
30	408	Other	15,775	4,879
31		Total Taxes Other Than Income Taxes	$6,149,421	$2,069,943
32		Interest on Customer Deposits		
33	431	Customer Deposit Interest Expense	$7,440	$0
34		Income Taxes		
35	409	Current Income Tax - State & Federal	$1,291,053	$399,355
36		Total Operating Expense - Excluding Income Taxes	$139,600,878	$9,970,689
37		Total Operating Expense - Including Taxes	$140,891,931	$10,370,044

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - DISTRIBUTION OF EXPENSE BY FUNCTION
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

				DEMAND	ENERGY			CUSTOMER			
LINE NO.	FERC ACCT.	FERC ACCOUNT DESCRIPTION	TOTAL COMPANY	DIST. SECONDARY	FUEL	Cust	Blank	Customer Delivery	METER	BILL & COLLECT	METER READING
		Steam Power Generation Expense									
1	500	Operation Supervision & Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	501	PPFAC - FUEL	0	0	0	0	0	0	0	0	0
3	502	Steam Expenses	0	0	0	0	0	0	0	0	0
4	505	Electric Expenses	0	0	0	0	0	0	0	0	0
5	506	Miscellaneous Steam Power Expenses	0	0	0	0	0	0	0	0	0
6	507	Rents	0	0	0	0	0	0	0	0	0
7	510	Maintenance Supervision & Engineering	0	0	0	0	0	0	0	0	0
8	511	Maintenance of Structures	0	0	0	0	0	0	0	0	0
9	512	Maintenance of Boiler Plant	0	0	0	0	0	0	0	0	0
10	513	Maintenance of Electric Plant	0	0	0	0	0	0	0	0	0
11	514	Maintenance Miscellaneous Steam Plant	0	0	0	0	0	0	0	0	0
12	411	FAS 143 Accretion Expense	0	0	0	0	0	0	0	0	0
13	412	Loss from Disposition of Utility Plant	0	0	0	0	0	0	0	0	0
14		Total Steam Power Generation Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0
15		Other Power Generation Expense									
16	546	Operation Supervision & Engineering	$3,405,721	$0	$0	$0	$0	$0	$0	$0	$0
17	547	PPFAC - Fuel	5,543,690	0	5,543,690	0	0	0	0	0	0
18	548 & 549	Generation Exp & Misc Other Power Generation	669,155	0	0	0	0	0	0	0	0
19	550	Rents	0	0	0	0	0	0	0	0	0
20	551	Maintenance Supervision & Engineering	6,512	0	0	0	0	0	0	0	0
21	552-554	Maintenance Structures, Generating, Other	1,384,519	0	0	0	0	0	0	0	0
22	407	Regulatory Asset Amortization	3,100,000	0	0	0	0	0	0	0	0
23		Total Other Power Generation Expense	$14,109,597	$0	$5,543,690	$0	$0	$0	$0	$0	$0
24		Total Production Expense	$14,109,597	$0	$5,543,690	$0	$0	$0	$0	$0	$0
25		Other Power Supply Expense									
26		PPFAC - Purchased Power									
27	555	PPFAC - DEMAND	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	555	PPFAC - ENERGY	62,964,670	0	62,964,670	0	0	0	0	0	0
29		TOTAL PURCHASED POWER	62,964,670	0	62,964,670	0	0	0	0	0	0
30	556	System Control and Load Dispatching	0	$0	$0	$0	$0	$0	$0	$0	$0
31	557	Other Expenses and Accretion Expense	916,543	0	0	0	0	0	0	0	0
32		Total Power Supply Expense	$63,881,212	$0	$62,964,670	$0	$0	$0	$0	$0	$0
33	565	Trans of Electricity by Others - PPFAC Eligible	$9,014,026	$0	$9,014,026	$0	$0	$0	$0	$0	$0
34	565	Trans of Electricity by Others - PPFAC Non-Eligible	14,531,456	0	0	0	0	0	0	0	0
35		Total Transmission Plant	$23,545,482	$0	$9,014,026	$0	$0	$0	$0	$0	$0

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - DISTRIBUTION OF EXPENSE BY FUNCTION
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE	FERC		TOTAL	DEMAND	ENERGY			CUSTOMER			
NO.	ACCT.	FERC ACCOUNT DESCRIPTION	COMPANY	DIST. SECONDARY	FUEL	Cust	Blank	Customer Delivery	METER	BILL & COLLECT	METER READING
		Distribution Plant									
1	580	Operation Supervision & Engineering	$416,745	$0	$0	$0	$0	$145,861	$0	$0	$0
2	581	Load Dispatching	860,035	0	0	0	0	0	0	0	0
3	582	Station Expenses	69,023	0	0	0	0	0	0	0	0
4	583	Overhead Line Expenses	542,487	0	0	0	0	189,870	0	0	0
5	584	Underground Line Expenses	309,851	0	0	0	0	309,851	0	0	0
6	585	Street Lighting & Signal System Expenses	0	0	0	0	0	0	0	0	0
7	586	Meter Expenses	721,222	0	0	0	0	0	721,222	0	0
8	587	Customer Installations Expense	76,287	0	0	0	0	0	76,287	0	0
9	588	Miscellaneous Distribution Expenses	756,371	0	0	0	0	453,823	0	0	0
10	589	Rents	26,605	0	0	0	0	0	0	0	0
11	590	Maintenance Supervision & Engineering	25	0	0	0	0	9	0	0	0
12	591	Maintenance of Structures	0	0	0	0	0	0	0	0	0
13	592	Maintenance of Station Equipment	903,797	0	0	0	0	0	0	0	0
14	593	Maintenance of Overhead Lines	589,548	0	0	0	0	206,342	0	0	0
15	594	Maintenance of Underground Lines	102,120	0	0	0	0	102,120	0	0	0
16	595	Maintenance of Line Transformers	92,619	0	0	0	0	55,571	0	0	0
17	596	Maintenance of Street Lighting & Signal Systems	27,094	27,094	0	0	0	0	0	0	0
18	597	Maintenance of Meters	2,080	0	0	0	0	0	2,080	0	0
19	598	Maintenance of Miscellaneous Distribution Plant	14,028	0	0	0	0	8,417	0	0	0
20	407	Regulatory Asset Amortization	0	0	0	0	0	0	0	0	0
21		Other	0	0	0	0	0	0	0	0	0
22		**Total Distribution Plant**	$5,509,935	$27,094	$0	$0	$0	$1,471,863	$799,590	$0	$0
		Customer Account Expense									
23	901	Supervision	$353,018	$0	$0	$0	$0	$0	$0	$288,056	$64,962
24	902	Meter Reading Expenses	651,708	0	0	0	0	0	0	0	651,708
25	903	Customer Records & Collection Expenses	2,889,804	0	0	0	0	0	0	2,889,804	0
26	904	Uncollectible Accounts	505,677	505,677	0	0	0	0	0	0	0
27	905	Miscellaneous Customer Accounts Expenses	(2,533)	0	0	0	0	0	0	(2,067)	(466)
28	908	Customer Assistance Expenses	121,102	0	0	0	0	0	0	98,817	22,285
29	909	Informational and Instructional Advertising Expenses	407,788	0	0	0	0	0	0	332,747	75,041
30	910	Miscellaneous Customer Service & Informational Expenses	2,496	0	0	0	0	0	0	2,037	459
31		Total Customer Account Expense	$4,929,060	$505,677	$0	$0	$0	$0	$0	$3,609,394	$813,989
32		Total Operation and Maintenance Expense Excluding Fuel & Power Supply Expense & A&G	$42,550,384	$532,771	$9,014,026	$0	$0	$1,471,863	$799,590	$3,609,394	$813,989
33	920-935	Administrative and General Expense	$8,409,208	$235,738	$0	$0	$0	$651,263	$353,799	$1,597,069	$360,171
34		Total Operation and Maintenance Expense	$120,384,494	$768,509	$77,522,385	$0	$0	$2,123,126	$1,153,389	$5,206,463	$1,174,160

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - DISTRIBUTION OF EXPENSE BY FUNCTION
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	FERC ACCT.	FERC ACCOUNT DESCRIPTION	TOTAL COMPANY	DEMAND	ENERGY			CUSTOMER			
				DIST. SECONDARY	FUEL	Cust	Blank	Customer Delivery	METER	BILL & COLLECT	METER READING
		Depreciation and Amortization									
1	301-303	Total Intangible Plant Depreciation Expense	$1,836,827	$102,656	$0	$0	$0	$531,897	$25,508	$0	$0
2	500-547	Production Depreciation Expense	$4,912,792	$0	$0	$0	$0	$0	$0	$0	$0
3		Transmission EXPENSE	$0	$0	$0	$0	$0	$0	$0	$0	$0
4		Transmission EXPENSE	0	0	0	0	0	0	0	0	0
5		Total Transmission Depreciation Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0
6		Distribution Plant Depreciation Expense									
7	360	Land & Rights	$1,070	$0	$0	$0	$0	$0	$0	$0	$0
8	361	Structures & Improvements	85,623	0	0	0	0	0	0	0	0
9	362	Station Equipment	913,346	0	0	0	0	0	0	0	0
10	364	Poles, Towers, & Fixtures	652,041	0	0	0	0	391,224	0	0	0
11	365	Overhead Conductors & Devices	734,953	0	0	0	0	257,234	0	0	0
12	366	Underground Conduit	211,032	0	0	0	0	211,032	0	0	0
13	367	Underground Conductors & Devices	546,264	355,072	0	0	0	191,192	0	0	0
14	368	Line Transformers	1,276,133	0	0	0	0	765,680	0	0	0
15	369	Services	155,540	0	0	0	0	155,540	0	0	0
16	370	Meters	220,357	0	0	0	0	0	220,357	0	0
17	373	Street Lighting & Signal Systems	54,913	54,913	0	0	0	0	0	0	0
18		Other	0	0	0	0	0	0	0	0	0
19		Total All Distribution Depreciation Expense	$4,851,273	$409,985	$0	$0	$0	$1,971,902	$220,357	$0	$0
20		General Plant Depreciation Expense	1,458,632	81,520	0	0	0	422,382	20,256	0	0
21		Total Depreciation Expense	$13,059,523	$594,161	$0	$0	$0	$2,926,181	$266,121	$0	$0
22		Taxes Other Than Income Taxes									
23	408	Property Tax - Production	$1,444,855	$0	$0	$0	$0	$0	$0	$0	$0
24	408	Property Tax - Transmission	0	0	0	0	0	0	0	0	0
25	408	Property Tax - Transmission	0	0	0	0	0	0	0	0	0
26	408	Property Tax - Distribution	4,010,589	335,204	0	0	0	1,736,814	83,292	0	0
27	408	Property Tax - General	234,225	13,090	0	0	0	67,826	3,253	0	0
28	408	Payroll	360,900	20,170	0	0	0	104,507	5,012	0	0
29	408	Medical and Dental	83,077	4,643	0	0	0	24,057	1,154	0	0
30	408	Other	15,775	882	0	0	0	4,568	219	0	0
31		Total Taxes Other Than Income Taxes	$6,149,421	$373,989	$0	$0	$0	$1,937,772	$92,929	$0	$0
32		Interest on Customer Deposits									
33	431	Customer Deposit Interest Expense	$7,440	$7,440	$0	$0	$0	$0	$0	$0	$0
34		Income Taxes									
35	409	Current Income Tax - State & Federal	$1,291,053	$72,154	$0	$0	$0	$373,855	$17,929	$0	$0
36		Total Operating Expense - Excluding Income Taxes	$139,600,878	$1,744,098	$77,522,385	$0	$0	$6,987,079	$1,512,439	$5,206,463	$1,174,160
37		Total Operating Expense - Including Taxes	$140,891,931	$1,816,252	$77,522,385	$0	$0	$7,360,935	$1,530,368	$5,206,463	$1,174,160

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - UNIT COST AT PROPOSED RATES
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

LINE NO.	REVENUES	TOTAL	TOTAL COMPANY	RESIDENTIAL	SMALL GENERAL SERVICE	MED./LRG. GENERAL SERVICE	LARGE POWER SERVCIE	LIGHTING
1	DEMAND COMPONENTS	$69,945,632	$69,945,632	$40,100,044	$5,839,278	$21,276,517	$2,316,873	$412,921
2	DEMAND PRODUCTION		34,791,933	19,373,582	2,887,441	10,836,983	1,604,208	89,720
3	DEMAND TRANSMISSION EXPENSE		14,531,456	8,787,564	1,250,088	3,855,128	615,035	23,642
4	DEMAND DISTRIBUTION PRIMARY		18,015,950	10,530,171	1,582,285	5,732,364	63,494	107,636
5	DEMAND DISTRIBUTION SECONDARY		2,606,293	1,408,727	119,465	852,042	34,136	191,923
6								
7	ENERGY COMPONENTS	77,522,385	77,522,385	40,227,839	5,768,557	27,305,258	4,183,666	37,065
8			77,522,385	40,227,839	5,768,557	27,305,258	4,183,666	37,065
9	CUSTOMER COMPONENTS	$22,259,721	$22,259,721	$13,881,792	$2,961,653	$5,144,524	$103,138	$168,615
10	CUSTOMER DELIVERY		13,569,942	8,132,828	1,198,195	4,141,731	43,055	54,135
11	CUSTOMER METERS		2,309,155	618,549	1,136,472	537,125	12,511	4,497
12	CUSTOMER BILLING & COLLECTIONS		5,206,463	4,174,431	510,347	379,776	38,817	103,092
13	CUSTOMER METER READING		1,174,160	955,984	116,638	85,892	8,755	6,892
14	TOTAL COMPANY	$169,727,738	$169,727,738	$94,209,675	$14,569,488	$53,726,298	$6,603,676	$618,601
15	PER UNIT COST		Per kWh	Per kWh	Per kWh	Per kW	Per kW	Per Watt
16	DEMAND COMPONENTS	$0.0437	$0.0437	$0.0487	$0.0492	$12.70	$13.47	$0.0551
17	DEMAND PRODUCTION		$0.0217	$0.0235	$0.0243	$6.47	$9.33	$0.0120
18	DEMAND TRANSMISSION EXPENSE		$0.0091	$0.0107	$0.0105	$2.30	$3.58	$0.0032
19	DEMAND DISTRIBUTION PRIMARY		$0.0113	$0.0128	$0.0133	$3.42	$0.37	$0.0144
20	DEMAND DISTRIBUTION SECONDARY		$0.0016	$0.0017	$0.0010	$0.51	$0.20	$0.0256
21	ENERGY COMPONENTS	$0.0484	$0.0484	$0.0488	$0.0486	$0.0485	$0.0451	$0.0131
22	ENERGY FUEL DIRECT		$0.0484	$0.0488	$0.0486	$0.0485	$0.0451	$0.0131
			Per Customer	Per Customer	Per Customer	Per Customer	Per Customer	Per Customer
23	CUSTOMER COMPONENTS	$19.4966	$19.50	$14.00	$28.18	$309.09	$2,148.71	$5.88
24	CUSTOMER DELIVERY		$11.89	$8.20	$11.40	$248.84	$896.98	$1.89
25	CUSTOMER METER READING		$2.02	$0.62	$10.81	$32.27	$260.66	$0.16
26	CUSTOMER BILLING & COLLECTIONS		$4.56	$4.21	$4.86	$22.82	$808.69	$3.60
27	CUSTOMER METERS		$1.03	$0.96	$1.11	$5.16	$182.39	$0.24
28	TOTAL COMPANY	$19.5887	$19.5887	$14.1014	$28.2783	$321.8448	$2,162.2247	$5.9482
29	TOTAL THRUPUT (kWh)	1,600,809,167	1,600,809,167	823,953,185	118,683,796	562,579,661	92,765,274	2,827,250
30	TOTAL ANNUAL CUSTOMERS	95,144	95,144	82,607	8,758	1,387	4	2,388
31	Wattage							7,490,450
32	TOTAL CUSTOMER ($/ CUSTOMER)		$19.50	$14.00	$28.18	$309.09	$2,148.71	$5.88
33	TOTAL DEMAND & CUSTOMER ($/ CUSTOMER)		$80.76	$54.46	$83.74	$1,587.42	$50,416.88	$20.29
34	DEMAND DETERMINANTS FOR APPLICABLE CLASSES					1,674,724	171,949	

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - DEVELOPMENT OF ALLOCATION FACTORS
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

Line No.	ALLOCATION FACTOR TABLE Description	Allocation	TOTAL COMPANY	DEMAND	ENERGY	CUSTOMER	RESIDENTIAL STANDARD SERVICE DEMAND	RESIDENTIAL STANDARD SERVICE ENERGY	RESIDENTIAL STANDARD SERVICE CUSTOMER
	ALLOCATION FACTOR TABLE								
	DEMAND - PRODUCTION RELATED								
1	DEMAND PRODUCTION	DPROD	334,908	334,908	0	0	202,528		
2	DEMAND - TRANSMISSION RELATED								
3	DEMAND TRANSMISSION	DTRAN	334,908	334,908	0	0	202,528	0	0
4	DEMAND SUBTRANSMISSION	DTRANSUB	334,908	334,908	0	0	202,528	0	0
	DEMAND - DISTRIBUTION RELATED								
5	DIST - CONDUIT	DDISTCON	418,023	0	0	418,023			267,360
6	DIST - PRI DIST SUBSTATIONS	DDISPSUB	418,023	418,023	0	0	267,360		
7	DIST - POLES TOWERS & FIXTURES	DDISPOLE	418,023	167,209	0	250,814	106,944		160,416
8	DIST - OVERHEAD CONDUCTORS	DDISTCON	418,023	271,715	0	146,308	173,784		93,576
9	DIST - UNDERGROUND CONDUIT	DDISTUCON	418,023	0	0	418,023	0		267,360
9	DIST - SEC UNDERGROUND DEVICES	DDISTUDEV	418,023	271,715	0	146,308	173,784		93,576
10	DIST - LINE TRANSFORMERS	DDISTLINET	418,023	167,209	0	250,814	106,944		160,416
11	DIST - STREET LIGHTING	DDISTLTG	1	1	0	0	0		
12	DIST - CUSTOMER DEPOSITS	DCUSTDEP	(4,414,345)	(4,414,345)	0	0	(2,181,567)		
13	DIST - CUSTOMER ADVANCES	DCUSTADV	(3,833,219)	(3,833,219)	0	0	(2,446,421)		
14	DIST - UNCOLLECTIBLES	DEUNCOL	69,654,260	33,425,187	36,229,073	0	33,425,187		
	ENERGY RELATED								
15	ENERGY PRODUCTION PWR SUPPLY	EFUEL	1,600,809,167	0	1,600,809,167	0		823,953,185	
16	ENERGY PRODUCTION	EPROD	334,908	334,908	0	0	202,528		
17	ENERGY - SYSTEM BENEFIT RELATED								
18	ENERGY PRODUCTION PWR SUPPLY-DESIGN	EFUELRD	77,522,386	0	77,522,386	0		40,227,839	
	CUSTOMER ALLOCATIONS								
19	YEAR END NUMBER OF CUSTOMERS	CUSTAVG	95,144			95,144			82,607
20	CUSTOMER DELIVERY	CUSTWGT	92,756			92,756			82,607
21	BILLING AND COLLECTION	CBILLCOL	95,144			95,144			82,607
22	CUSTOMER ACCOUNTING	CACCT	92,756			92,756			82,607
1	CUSTOMER INFORMATION	DCUSINFO	95,144	0	0	95,144			82,607
2	CUSTOMER INFORMATION	CCUSINFO	350,880,250	191,641,961	0	159,238,288	120,029,063	0	101,961,841
25	METER READING	CMETRDG	92,756			92,756			82,607
23	METERS	CMETERS	32,340,527			32,340,527			5,626,590
24	STREET LIGHTING	CLIGHT	2,388			2,388			0
	INTERNALLY DEVELOPED								
25	PLANT IN SERVICE EXCL GENERAL DEMAND	PISXGENL	524,740,517	365,502,229	0	159,238,288	225,167,067	0	101,961,841
26	PLANT IN SERVICE EXCL GENERAL CUST	PISXGENL	159,238,288	0	0	159,238,288	0	0	101,961,841
27	TOTAL PLANT IN SERVICE DEMAND	TOTPIS	569,545,363	311,071,343	0	258,474,020	193,925,236		161,135,497
28	TOTAL PLANT IN SERVICE CUST	TOTPIS	172,834,812	0	0	172,834,812	0	0	110,667,829
29	PRODUCTION PLANT IN SERVICE	PRODPIS	173,860,268	173,860,268	0	0	105,138,005	0	0
30	TRANSMISSION PLANT IN SERVICE	TRANPIS	0	0	0	0	0	0	0
31	DISTRIBUTION PLANT IN SERVICE DEMAND	DISTPIS	191,641,961	191,641,961	0	0	120,029,063	0	0
32	DISTRIBUTION PLANT IN SERVICE CUST	DISTPIS	350,880,250	191,641,961	0	159,238,288	120,029,063	0	101,961,841
33	TOTAL TRANSMISSION & DISTRIBUTION	TDPLT	191,641,961	191,641,961	0	0	120,029,063	0	0
34	GENERAL PLANT	GENLPIS	524,740,517	365,502,229	0	159,238,288	225,167,067	0	101,961,841
35	GENERAL PLANT	GENLPIS	159,238,288	0	0	159,238,288	0	0	101,961,841
36	TEST YEAR ADJUSTED SALES (kWh)	SALESREV	1,600,809,167	1,600,809,167	0	0	823,953,185	0	0
37	TOTAL O&M LESS FUEL & PP	OM	33,536,358	26,843,572	0	6,692,785	16,240,755		4,934,265

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FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

Line No.	ALLOCATION FACTOR TABLE Description	Allocation	TOTAL COMPANY	DEMAND	ENERGY	CUSTOMER	RESIDENTIAL STANDARD SERVICE DEMAND	ENERGY	CUSTOMER
1	ACCOUNT 360	ACC362-368	837,790	837,790	0	0	535,835	0	0
2	ACCOUNT 361	PLT361	837,790	837,790	0	0	535,835	0	0
3	ACCOUNT 362	PLT362	58,174,288	58,174,288	0	0	37,207,217	0	0
4	ACCOUNT 364	PLT364	74,467,314	29,786,926	0	44,680,388	19,051,176	0	28,576,764
5	ACCOUNT 365	PLT365	63,488,578	41,267,575	0	22,221,002	26,393,991	0	14,212,149
6	ACCOUNT 366	PLT366	18,173,564	0	0	18,173,564	0	0	11,623,481
7	ACCOUNT 367	PLT367	39,003,990	25,352,594	0	13,651,397	16,215,058	0	8,731,185
8	ACCOUNT 368	PLT368	65,409,315	26,163,726	0	39,245,589	16,733,843	0	25,100,765
9	ACCOUNT 369	PLT369	13,979,252	0	0	13,979,252	0	0	12,449,691
10	ACCOUNT 370	PLT370	7,287,096	0	0	7,287,096	0	0	1,267,806
11	ACCOUNT 373	PLT373	3,973,928	3,973,928	0	0	0	0	0
12	OVERHEAD DISTRIBUTION PLANT IN SERVICE	OHDIST	63,488,578	41,267,575	0	22,221,002	26,393,991	0	14,212,149
13	UNDERGROUND DISTRIBUTION PLT IN SERVICE	UGDIST	18,173,564	0	0	18,173,564	0	0	11,623,481
14	TOTAL O&M EXCLUDING GENERAL	OMXGENL	26,843,572	26,843,572	0	0	16,240,755	0	0
15	TOTAL O&M EXCLUDING GENERAL	OMXGENL	6,692,785	0	0	6,692,785	0	0	4,934,265
16	LABOR ACCOUNTS 581-589	LAB58189	40,236,966	26,154,028	0	14,082,938	16,727,641	0	9,007,191
17	LABOR ACCOUNTS 581-589	LAB58189	1,751,053		0	1,751,053		0	748,620
18	LABOR ACCOUNTS 591-598	LAB59198	1,358,806	1,358,806	0		839,651	0	
19	LABOR ACCOUNTS 591-598	LAB59198	372,479	0	0	372,479		0	237,267
31	LABOR CUSTOMER ACCOUNT EXPENSE	LAB900	4,576,042	0	0	4,576,042		0	3,791,242
32	RATIO TABLE								
33	DEMAND RELATED								
34	DEMAND - PRODUCTION RELATED								
35	DEMAND PRODUCTION	DPROD	1.00	1.00	0.00	0.00	0.6047	0.0000	0.0000
36	DEMAND - TRANSMISSION RELATED								
37	DEMAND TRANSMISSION	DTRAN	1.00	1.00	0.00	0.00	0.6047	0.0000	0.0000
38	DEMAND TRANSMISSION	DTRAN	1.00	1.00	0.00	0.00	0.6047	0.0000	0.0000
39	DEMAND - DISTRIBUTION RELATED								
40	DIST - PRI DIST SUBSTATIONS	DDISPSUB	1.00	1.00	0.00	0.00	0.6396	0.0000	0.0000
41	DIST - POLES TOWERS & FIXTURES	DDISPOLE	1.00	0.40	0.00	0.60	0.2558	0.0000	0.3837
42	DIST - OVERHEAD CONDUCTORS	DDISTCON	1.00	0.65	0.00	0.35	0.4157	0.0000	0.2239
43	DIST - UNDERGROUND CONDUIT	DDISTUCON	1.00	0.00	0.00	1.00	0.0000	0.0000	0.6396
44	DIST - SEC UNDERGROUND DEVICES	DDISTUDEV	1.00	0.65	0.00	0.35	0.4157	0.0000	0.2239
45	DIST - LINE TRANSFORMERS	DDISTLINET	1.00	0.40	0.00	0.60	0.2558	0.0000	0.3837
46	DIST - STREET LIGHTING	DDISTLTG	1.00	1.00	0.00	0.00	0.0000	0.0000	0.0000
47	DIST - CUSTOMER DEPOSITS	DCUSTDEP	1.00	1.00	0.00	0.00	0.4942	0.0000	0.0000
48	DIST - CUSTOMER ADVANCES	DCUSTADV	1.00	1.00	0.00	0.00	0.6382	0.0000	0.0000
49	DIST - UNCOLLECTIBLES	DEUNCOL	1.00	1.00	0.00	0.00	0.4799	0.0000	0.0000
	ENERGY RELATED								
50	ENERGY PRODUCTION PWR SUPPLY	EFUEL	1.00	0.00	1.00	0.00	0.0000	0.5147	0.0000
51	ENERGY PRODUCTION	EPROD	1.00	1.00	0.00	0.00	0.6047	0.0000	0.0000
52	ENERGY - SYSTEM BENEFIT RELATED								
53	ENERGY PRODUCTION PWR SUPPLY-DESIGN	EFUELRD	1.00	0.00	1.00	0.00	0.0000	0.5189	0.0000

UNS ELECTRIC, INC.
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FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

Line No.	ALLOCATION FACTOR TABLE Description	Allocation	TOTAL COMPANY	DEMAND	ENERGY	CUSTOMER	RESIDENTIAL STANDARD SERVICE DEMAND	 ENERGY	 CUSTOMER
	UNWEIGHTED CUSTOMER BILLS	CUSTWGT	1.00	0.00	0.00	1.00	0.0000	0.0000	0.8682
1	CUSTOMER SUPERVISION	CSUPV	1.00	0.55	0.00	0.45	0.3420	0.0000	0.2907
2	CUSTOMER INFORMATION	DCUSINFO	1.00	0.00	0.00	1.00	0.0000	0.0000	0.8682
3	CUSTOMER INFORMATION	CCUSINFO	1.00	0.55	0.00	0.45	0.3421	0.0000	0.2906
4	METER READING	CREAD	1.00	0.00	0.00	1.00	0.0000	0.0000	0.8906
5	CUSTOMER DELIVERY	CUST	1.00	0.00	0.00	1.00	0.0000	0.0000	0.8906
6	BILLING AND COLLECTION	CBILLCOL	1.00	0.00	0.00	1.00	0.0000	0.0000	0.8682
7	CUSTOMER ACCOUNTING	CACCT	1.00	0.00	0.00	1.00	0.0000	0.0000	0.8906
8	METERS	CMETERS	1.00	0.00	0.00	1.00	0.0000	0.0000	0.1740
9	STREET LIGHTING	CLIGHT	1.00	0.00	0.00	1.00	0.0000	0.0000	0.0000
10	INTERNALLY DEVELOPED								
11	PLANT IN SERVICE EXCL GENERAL DEMAND	PISXGENL	1.00	0.70	0.00	0.30	0.4291	0.0000	0.1943
12	PLANT IN SERVICE EXCL GENERAL CUST	PISXGENL	1.00	0.00	0.00	1.00	0.0000	0.0000	0.6403
13	TOTAL PLANT IN SERVICE DEMCUST	TOTPIS	1.00	0.55	0.00	0.45	0.3405	0.0000	0.2829
14	TOTAL PLANT IN SERVICE DEMAND	TOTPIS	1.00	0.70	0.00	0.30	0.4291	0.0000	0.1943
15	PRODUCTION PLANT IN SERVICE	PRODPIS	1.00	1.00	0.00	0.00	0.6047	0.0000	0.0000
16	TRANSMISSION PLANT IN SERVICE	TRANPIS	0.00	0.00	0.00	0.00	0.0000	0.0000	0.0000
17	DISTRIBUTION PLANT IN SERVICE DEMAND	DISTPIS	1.00	1.00	0.00	0.00	0.6263	0.0000	0.0000
18	DISTRIBUTION PLANT IN SERVICE DEMAND &CUST	DISTPIS	1.00	0.55	0.00	0.45	0.3421	0.0000	0.2906
19	TOTAL TRANSMISSION & DISTRIBUTION	TDPLT	1.00	1.00	0.00	0.00	0.6263	0.0000	0.0000
20	GENERAL PLANT	GENLPIS	1.00	0.70	0.00	0.30	0.4291	0.0000	0.1943
21	GENERAL PLANT	GENLPIS	1.00	0.00	0.00	1.00	0.0000	0.0000	0.6403
22	BASE RATE SALES REVENUE	SALESREV	1.00	1.00	0.00	0.00	0.5147	0.0000	0.0000
23	MISC. SERVICE REVENUE ACCT 451		1,386,204	0	0	1,386,204			1,100,159
24	TOTAL O&M LESS FUEL & PP	OM	1.00	0.70	0.00	0.30	0.4291	0.0000	0.1943
25	ACCOUNT 360	PLT360	1.00	1.00	0.00	0.00	0.6396	0.0000	0.0000
26	ACCOUNT 361	PLT361	1.00	1.00	0.00	0.00	0.6396	0.0000	0.0000
27	ACCOUNT 362	PLT362	1.00	1.00	0.00	0.00	0.6396	0.0000	0.0000
28	ACCOUNT 364	PLT364	1.00	0.40	0.00	0.60	0.2558	0.0000	0.3837
29	ACCOUNT 365	PLT365	1.00	0.65	0.00	0.35	0.4157	0.0000	0.2239
30	ACCOUNT 366	PLT366	1.00	0.00	0.00	1.00	0.0000	0.0000	0.6396
31	ACCOUNT 367	PLT367	1.00	0.65	0.00	0.35	0.4157	0.0000	0.2239
32	ACCOUNT 368	PLT368	1.00	0.40	0.00	0.60	0.2558	0.0000	0.3837
33	ACCOUNT 369	PLT369	1.00	0.00	0.00	1.00	0.0000	0.0000	0.8906
34	ACCOUNT 370	PLT370	1.00	0.00	0.00	1.00	0.0000	0.0000	0.1740
35	ACCOUNT 373	PLT373	1.00	1.00	0.00	0.00	0.0000	0.0000	0.0000
36	OVERHEAD DISTRIBUTION PLANT IN SERVICE	OHDIST	1.00	0.65	0.00	0.35	0.4157	0.0000	0.2239
37	UNDERGROUND DISTRIBUTION PLT IN SERVICE	UGDIST	1.00	0.00	0.00	1.00	0.0000	0.0000	0.6396
38	TOTAL O&M EXCLUDING GENERAL	OMXGENL	1.00	1.00	0.00	0.00	0.6050	0.0000	0.0000
39	TOTAL O&M EXCLUDING GENERAL	OMXGENL	1.00	0.00	0.00	1.00	0.0000	0.0000	0.7373
40	LABOR ACCOUNTS 581-589	LAB58189	1.00	0.65	0.00	0.35	0.4157	0.0000	0.2239
41	LABOR ACCOUNTS 581-589	LAB58189	1.00	0.00	0.00	1.00	0.0000	0.0000	0.4275
42	LABOR ACCOUNTS 591-598	LAB59198	1.00	1.00	0.00	0.00	0.6179	0.0000	0.0000
43	LABOR ACCOUNTS 591-598	LAB59198	1.00	0.00	0.00	1.00	0.0000	0.0000	0.6370
44	PROPOSED TAX EXPENSE	TOTPIS	1.00	0.55	0.00	0.45	0.3405	0.0000	0.2829
45	LABOR 902-910	LAB9029100	1.00	0.70	0.00	0.30	0.4291	0.0000	0.1943
46	LABOR CUSTOMER ACCOUNT EXPENSE	LAB900	1.00	0.00	0.00	1.00	0.0000	0.0000	0.8285

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CLASS COST OF SERVICE STUDY - DEVELOPMENT OF ALLOCATION FACTORS
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

Line No.	ALLOCATION FACTOR TABLE Description	Allocation	SMALL GENERAL SERVICE DEMAND	ENERGY	CUSTOMER	MEDIUM/ LARGE GENERAL SERVICE DEMAND	ENERGY	CUSTOMER
	ALLOCATION FACTOR TABLE							
	DEMAND - PRODUCTION RELATED							
1	DEMAND PRODUCTION	DPROD	28,811			88,849		
2	DEMAND - TRANSMISSION RELATED							
3	DEMAND TRANSMISSION	DTRAN	28,811	0	0	88,849	0	0
4	DEMAND SUBTRANSMISSION	DTRANSUB	28,811	0	0	88,849	0	0
	DEMAND - DISTRIBUTION RELATED							
5	DIST - CONDUIT	DDISTCON			37,995			111,965
6	DIST - PRI DIST SUBSTATIONS	DDISPSUB	37,995			111,965		
7	DIST - POLES TOWERS & FIXTURES	DDISPOLE	15,198		22,797	44,786		67,179
8	DIST - OVERHEAD CONDUCTORS	DDISTCON	24,697		13,298	72,777		39,188
9	DIST - UNDERGROUND CONDUIT	DDISTUCON	0		37,995	0		111,965
9	DIST - SEC UNDERGROUND DEVICES	DDISTUDEV	24,697		13,298	72,777		39,188
10	DIST - LINE TRANSFORMERS	DDISTLINET	15,198		22,797	44,786		67,179
11	DIST - STREET LIGHTING	DDISTLTG	0			0		
12	DIST - CUSTOMER DEPOSITS	DCUSTDEP	(1,927,517)			(305,260)		
13	DIST - CUSTOMER ADVANCES	DCUSTADV	(378,008)			(1,008,789)		
14	DIST - UNCOLLECTIBLES	DEUNCOL	6,136,594			26,394,695		
	ENERGY RELATED							
15	ENERGY PRODUCTION PWR SUPPLY	EFUEL		118,683,796			562,579,661	
16	ENERGY PRODUCTION	EPROD	28,811			88,849		
17	ENERGY - SYSTEM BENEFIT RELATED							
18	ENERGY PRODUCTION PWR SUPPLY-DESIGN	EFUELRD		5,768,557			27,305,258	
	CUSTOMER ALLOCATIONS							
19	YEAR END NUMBER OF CUSTOMERS	CUSTAVG			8,758			1,387
20	CUSTOMER DELIVERY	CUSTWGT			8,758			1,387
21	BILLING AND COLLECTION	CBILLCOL			8,758			1,387
22	CUSTOMER ACCOUNTING	CACCT			8,758			1,387
1	CUSTOMER INFORMATION	DCUSINFO	0	0	8,758	0	0	1,387
2	CUSTOMER INFORMATION	CCUSINFO	17,057,415	0	18,532,318	50,265,894	0	38,502,419
25	METER READING	CMETRDG	0	0	8,758	0	0	1,387
23	METERS	CMETERS			20,734,273			5,939,564
24	STREET LIGHTING	CLIGHT			0			0
	INTERNALLY DEVELOPED							
25	PLANT IN SERVICE EXCL GENERAL DEMAND	PISXGENL	32,013,974	0	18,532,318	96,390,213	0	38,502,419
26	PLANT IN SERVICE EXCL GENERAL CUST	PISXGENL	0	0	18,532,318	0	0	38,502,419
27	TOTAL PLANT IN SERVICE DEMAND	TOTPIS	29,964,339		24,897,836	79,965,680		66,444,728
28	TOTAL PLANT IN SERVICE CUST	TOTPIS	0	0	20,114,696	0	0	41,789,939
29	PRODUCTION PLANT IN SERVICE	PRODPIS	14,956,558	0	0	46,124,319	0	0
30	TRANSMISSION PLANT IN SERVICE	TRANPIS	0	0	0	0	0	0
31	DISTRIBUTION PLANT IN SERVICE DEMAND	DISTPIS	17,057,415	0	0	50,265,894	0	0
32	DISTRIBUTION PLANT IN SERVICE CUST	DISTPIS	17,057,415	0	18,532,318	50,265,894	0	38,502,419
33	TOTAL TRANSMISSION & DISTRIBUTION	TDPLT	17,057,415	0	0	50,265,894	0	0
34	GENERAL PLANT	GENLPIS	32,013,974	0	18,532,318	96,390,213	0	38,502,419
35	GENERAL PLANT	GENLPIS	0	0	18,532,318	0	0	38,502,419
36	TEST YEAR ADJUSTED SALES (kWh)	SALESREV	118,683,796	0	0	562,579,661	0	0
37	TOTAL O&M LESS FUEL & PP	OM	2,320,087		1,055,109	7,169,576		605,094

UNS ELECTRIC, INC.
CLASS COST OF SERVICE STUDY - DEVELOPMENT OF ALLOCATION FACTORS
FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

Line No.	ALLOCATION FACTOR TABLE Description	Allocation	SMALL GENERAL SERVICE DEMAND	ENERGY	CUSTOMER	MEDIUM/ LARGE GENERAL SERVICE DEMAND	ENERGY	CUSTOMER
1	ACCOUNT 360	ACC362-368	76,148	0	0	224,398	0	0
2	ACCOUNT 361	PLT361	76,148	0	0	224,398	0	0
3	ACCOUNT 362	PLT362	5,287,544	0	0	15,581,677	0	0
4	ACCOUNT 364	PLT364	2,707,376	0	4,061,064	7,978,271	0	11,967,407
5	ACCOUNT 365	PLT365	3,750,869	0	2,019,699	11,053,303	0	5,951,778
6	ACCOUNT 366	PLT366	0	0	1,651,821	0	0	4,867,693
7	ACCOUNT 367	PLT367	2,304,333	0	1,240,795	6,790,559	0	3,656,455
8	ACCOUNT 368	PLT368	2,378,058	0	3,567,088	7,007,816	0	10,511,724
9	ACCOUNT 369	PLT369	0	0	1,319,922	0	0	209,035
10	ACCOUNT 370	PLT370	0	0	4,671,929	0	0	1,338,326
11	ACCOUNT 373	PLT373	0	0	0	0	0	0
12	OVERHEAD DISTRIBUTION PLANT IN SERVICE	OHDIST	3,750,869	0	2,019,699	11,053,303	0	5,951,778
13	UNDERGROUND DISTRIBUTION PLT IN SERVICE	UGDIST	0	0	1,651,821	0	0	4,867,693
14	TOTAL O&M EXCLUDING GENERAL	OMXGENL	2,320,087	0	0	7,169,576	0	0
15	TOTAL O&M EXCLUDING GENERAL	OMXGENL	0	0	1,055,109	0	0	605,094
16	LABOR ACCOUNTS 581-589	LAB58189	2,377,177	0	1,280,018	7,005,219	0	3,772,041
17	LABOR ACCOUNTS 581-589	LAB58189		0	597,971		0	401,870
18	LABOR ACCOUNTS 591-598	LAB59198	119,323	0		351,630	0	
19	LABOR ACCOUNTS 591-598	LAB59198		0	35,162		0	99,426
31	LABOR CUSTOMER ACCOUNT EXPENSE	LAB900			420,773			251,203
32	RATIO TABLE							
33	DEMAND RELATED							
34	DEMAND - PRODUCTION RELATED							
35	DEMAND PRODUCTION	DPROD	0.0860	0.0000	0.0000	0.2653	0.0000	0.0000
36	DEMAND - TRANSMISSION RELATED							
37	DEMAND TRANSMISSION	DTRAN	0.0860	0.0000	0.0000	0.2653	0.0000	0.0000
38	DEMAND TRANSMISSION	DTRAN	0.0860	0.0000	0.0000	0.2653	0.0000	0.0000
39	DEMAND - DISTRIBUTION RELATED							
40	DIST - PRI DIST SUBSTATIONS	DDISPSUB	0.0909	0.0000	0.0000	0.2678	0.0000	0.0000
41	DIST - POLES TOWERS & FIXTURES	DDISPOLE	0.0364	0.0000	0.0545	0.1071	0.0000	0.1607
42	DIST - OVERHEAD CONDUCTORS	DDISTCON	0.0591	0.0000	0.0318	0.1741	0.0000	0.0937
43	DIST - UNDERGROUND CONDUIT	DDISTUCON	0.0000	0.0000	0.0909	0.0000	0.0000	0.2678
44	DIST - SEC UNDERGROUND DEVICES	DDISTUDEV	0.0591	0.0000	0.0318	0.1741	0.0000	0.0937
45	DIST - LINE TRANSFORMERS	DDISTLINET	0.0364	0.0000	0.0545	0.1071	0.0000	0.1607
46	DIST - STREET LIGHTING	DDISTLTG	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
47	DIST - CUSTOMER DEPOSITS	DCUSTDEP	0.4366	0.0000	0.0000	0.0692	0.0000	0.0000
48	DIST - CUSTOMER ADVANCES	DCUSTADV	0.0986	0.0000	0.0000	0.2632	0.0000	0.0000
49	DIST - UNCOLLECTIBLES	DEUNCOL	0.0881	0.0000	0.0000	0.3789	0.0000	0.0000
	ENERGY RELATED							
50	ENERGY PRODUCTION PWR SUPPLY	EFUEL	0.0000	0.0741	0.0000	0.0000	0.3514	0.0000
51	ENERGY PRODUCTION	EPROD	0.0860	0.0000	0.0000	0.2653	0.0000	0.0000
52	ENERGY - SYSTEM BENEFIT RELATED							
53	ENERGY PRODUCTION PWR SUPPLY-DESIGN	EFUELRD	0.0000	0.0744	0.0000	0.0000	0.3522	0.0000

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CLASS COST OF SERVICE STUDY - DEVELOPMENT OF ALLOCATION FACTORS
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Line No.	ALLOCATION FACTOR TABLE Description	Allocation	SMALL GENERAL SERVICE DEMAND	SMALL GENERAL SERVICE ENERGY	SMALL GENERAL SERVICE CUSTOMER	MEDIUM/ LARGE GENERAL SERVICE DEMAND	MEDIUM/ LARGE GENERAL SERVICE ENERGY	MEDIUM/ LARGE GENERAL SERVICE CUSTOMER
	UNWEIGHTED CUSTOMER BILLS	CUSTWGT	0.0000	0.0000	0.0921	0.0000	0.0000	0.0146
1	CUSTOMER SUPERVISION	CSUPV	0.0486	0.0000	0.0528	0.1432	0.0000	0.1097
2	CUSTOMER INFORMATION	DCUSINFO	0.0000	0.0000	0.0921	0.0000	0.0000	0.0146
3	CUSTOMER INFORMATION	CCUSINFO	0.0486	0.0000	0.0528	0.1433	0.0000	0.1097
4	METER READING	CREAD	0.0000	0.0000	0.0944	0.0000	0.0000	0.0150
5	CUSTOMER DELIVERY	CUST	0.0000	0.0000	0.0944	0.0000	0.0000	0.0150
6	BILLING AND COLLECTION	CBILLCOL	0.0000	0.0000	0.0921	0.0000	0.0000	0.0146
7	CUSTOMER ACCOUNTING	CACCT	0.0000	0.0000	0.0944	0.0000	0.0000	0.0150
8	METERS	CMETERS	0.0000	0.0000	0.6411	0.0000	0.0000	0.1837
9	STREET LIGHTING	CLIGHT	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
10	INTERNALLY DEVELOPED							
11	PLANT IN SERVICE EXCL GENERAL DEMAND	PISXGENL	0.0610	0.0000	0.0353	0.1837	0.0000	0.0734
12	PLANT IN SERVICE EXCL GENERAL CUST	PISXGENL	0.0000	0.0000	0.1164	0.0000	0.0000	0.2418
13	TOTAL PLANT IN SERVICE DEMCUST	TOTPIS	0.0526	0.0000	0.0437	0.1404	0.0000	0.1167
14	TOTAL PLANT IN SERVICE DEMAND	TOTPIS	0.0610	0.0000	0.0353	0.1837	0.0000	0.0734
15	PRODUCTION PLANT IN SERVICE	PRODPIS	0.0860	0.0000	0.0000	0.2653	0.0000	0.0000
16	TRANSMISSION PLANT IN SERVICE	TRANPIS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
17	DISTRIBUTION PLANT IN SERVICE DEMAND	DISTPIS	0.0890	0.0000	0.0000	0.2623	0.0000	0.0000
18	DISTRIBUTION PLANT IN SERVICE DEMAND &CUST	DISTPIS	0.0486	0.0000	0.0528	0.1433	0.0000	0.1097
19	TOTAL TRANSMISSION & DISTRIBUTION	TDPLT	0.0890	0.0000	0.0000	0.2623	0.0000	0.0000
20	GENERAL PLANT	GENLPIS	0.0610	0.0000	0.0353	0.1837	0.0000	0.0734
21	GENERAL PLANT	GENLPIS	0.0000	0.0000	0.1164	0.0000	0.0000	0.2418
22	BASE RATE SALES REVENUE	SALESREV	0.0741	0.0000	0.0000	0.3514	0.0000	0.0000
23	MISC. SERVICE REVENUE ACCT 451				172,379			113,665
24	TOTAL O&M LESS FUEL & PP	OM	0.0610	0.0000	0.0353	0.1837	0.0000	0.0734
25	ACCOUNT 360	PLT360	0.0909	0.0000	0.0000	0.2678	0.0000	0.0000
26	ACCOUNT 361	PLT361	0.0909	0.0000	0.0000	0.2678	0.0000	0.0000
27	ACCOUNT 362	PLT362	0.0909	0.0000	0.0000	0.2678	0.0000	0.0000
28	ACCOUNT 364	PLT364	0.0364	0.0000	0.0545	0.1071	0.0000	0.1607
29	ACCOUNT 365	PLT365	0.0591	0.0000	0.0318	0.1741	0.0000	0.0937
30	ACCOUNT 366	PLT366	0.0000	0.0000	0.0909	0.0000	0.0000	0.2678
31	ACCOUNT 367	PLT367	0.0591	0.0000	0.0318	0.1741	0.0000	0.0937
32	ACCOUNT 368	PLT368	0.0364	0.0000	0.0545	0.1071	0.0000	0.1607
33	ACCOUNT 369	PLT369	0.0000	0.0000	0.0944	0.0000	0.0000	0.0150
34	ACCOUNT 370	PLT370	0.0000	0.0000	0.6411	0.0000	0.0000	0.1837
35	ACCOUNT 373	PLT373	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
36	OVERHEAD DISTRIBUTION PLANT IN SERVICE	OHDIST	0.0591	0.0000	0.0318	0.1741	0.0000	0.0937
37	UNDERGROUND DISTRIBUTION PLT IN SERVICE	UGDIST	0.0000	0.0000	0.0909	0.0000	0.0000	0.2678
38	TOTAL O&M EXCLUDING GENERAL	OMXGENL	0.0864	0.0000	0.0000	0.2671	0.0000	0.0000
39	TOTAL O&M EXCLUDING GENERAL	OMXGENL	0.0000	0.0000	0.1576	0.0000	0.0000	0.0904
40	LABOR ACCOUNTS 581-589	LAB58189	0.0591	0.0000	0.0318	0.1741	0.0000	0.0937
41	LABOR ACCOUNTS 581-589	LAB58189	0.0000	0.0000	0.3415	0.0000	0.0000	0.2295
42	LABOR ACCOUNTS 591-598	LAB59198	0.0878	0.0000	0.0000	0.2588	0.0000	0.0000
43	LABOR ACCOUNTS 591-598	LAB59198	0.0000	0.0000	0.0944	0.0000	0.0000	0.2669
44	PROPOSED TAX EXPENSE	TOTPIS	0.0526	0.0000	0.0437	0.1404	0.0000	0.1167
45	LABOR 902-910	LAB9029100	0.0610	0.0000	0.0353	0.1837	0.0000	0.0734
46	LABOR CUSTOMER ACCOUNT EXPENSE	LAB900	0.0000	0.0000	0.0920	0.0000	0.0000	0.0549

UNS ELECTRIC, INC.
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FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

Line No.	ALLOCATION FACTOR TABLE Description	Allocation	LARGE POWER SERVCIE DEMAND	LARGE POWER SERVCIE ENERGY	LARGE POWER SERVCIE CUSTOMER	LIGHTING DEMAND	LIGHTING ENERGY	LIGHTING CUSTOMER
	ALLOCATION FACTOR TABLE							
	DEMAND - PRODUCTION RELATED							
1	DEMAND PRODUCTION	DPROD	14,175			545		
2	DEMAND - TRANSMISSION RELATED							
3	DEMAND TRANSMISSION	DTRAN	14,175	0	0	545		
4	DEMAND SUBTRANSMISSION	DTRANSUB	14,175	0	0	545		
	DEMAND - DISTRIBUTION RELATED							
5	DIST - CONDUIT	DDISTCON			0			703
6	DIST - PRI DIST SUBSTATIONS	DDISPSUB	0			703		
7	DIST - POLES TOWERS & FIXTURES	DDISPOLE	0		0	281		422
8	DIST - OVERHEAD CONDUCTORS	DDISTCON	0		0	457		246
9	DIST - UNDERGROUND CONDUIT	DDISTUCON	0		0	0		703
9	DIST - SEC UNDERGROUND DEVICES	DDISTUDEV	0		0	457		246
10	DIST - LINE TRANSFORMERS	DDISTLINET	0		0	281		422
11	DIST - STREET LIGHTING	DDISTLTG	0			1		
12	DIST - CUSTOMER DEPOSITS	DCUSTDEP	0			0		
13	DIST - CUSTOMER ADVANCES	DCUSTADV	0			0		
14	DIST - UNCOLLECTIBLES	DEUNCOL	3,191,840			505,944		
	ENERGY RELATED							
15	ENERGY PRODUCTION PWR SUPPLY	EFUEL	0	92,765,274			2,827,250	
16	ENERGY PRODUCTION	EPROD	14,175			545		
17	ENERGY - SYSTEM BENEFIT RELATED							
18	ENERGY PRODUCTION PWR SUPPLY-DESIGN	EFUELRD		4,183,666			37,065	
	CUSTOMER ALLOCATIONS							
19	YEAR END NUMBER OF CUSTOMERS	CUSTAVG			4			2,388
20	CUSTOMER DELIVERY	CUSTWGT			4			0
21	BILLING AND COLLECTION	CBILLCOL	0	0	4			2,388
22	CUSTOMER ACCOUNTING	CACCT	0	0	4			0
1	CUSTOMER INFORMATION	DCUSINFO	0	0	4	0	0	2,388
2	CUSTOMER INFORMATION	CCUSINFO	0	0	9,638	4,289,589	0	232,071
25	METER READING	CMETRDG	0	0	4	0	0	0
23	METERS	CMETERS			40,100			0
24	STREET LIGHTING	CLIGHT			0			2,388
	INTERNALLY DEVELOPED							
25	PLANT IN SERVICE EXCL GENERAL DEMAND	PISXGENL	7,358,528	0	9,638	4,572,447	0	232,071
26	PLANT IN SERVICE EXCL GENERAL CUST	PISXGENL	0	0	9,638	0	0	232,071
27	TOTAL PLANT IN SERVICE DEMAND	TOTPIS	4,367,921		3,629,374	2,848,166		2,366,586
28	TOTAL PLANT IN SERVICE CUST	TOTPIS	0	0	10,461	0	0	251,887
29	PRODUCTION PLANT IN SERVICE	PRODPIS	7,358,528	0	0	282,858	0	0
30	TRANSMISSION PLANT IN SERVICE	TRANPIS	0	0	0	0	0	0
31	DISTRIBUTION PLANT IN SERVICE DEMAND	DISTPIS	0	0	0	4,289,589	0	0
32	DISTRIBUTION PLANT IN SERVICE CUST	DISTPIS	0	0	9,638	4,289,589	0	232,071
33	TOTAL TRANSMISSION & DISTRIBUTION	TDPLT	0	0	0	4,289,589	0	0
34	GENERAL PLANT	GENLPIS	7,358,528	0	9,638	4,572,447	0	232,071
35	GENERAL PLANT	GENLPIS	0	0	9,638	0	0	232,071
36	TEST YEAR ADJUSTED SALES (kWh)	SALESREV	92,765,274	0	0	2,827,250	0	0
37	TOTAL O&M LESS FUEL & PP	OM	1,000,754		1,178	112,402		97,139

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Line No.	ALLOCATION FACTOR TABLE Description	Allocation	LARGE POWER SERVCIE DEMAND	ENERGY	CUSTOMER	LIGHTING DEMAND	ENERGY	CUSTOMER
1	ACCOUNT 360	ACC362-368	0	0	0	1,409	0	0
2	ACCOUNT 361	PLT361	0	0	0	1,409	0	0
3	ACCOUNT 362	PLT362	0	0	0	97,850	0	0
4	ACCOUNT 364	PLT364	0	0	0	50,102	0	75,153
5	ACCOUNT 365	PLT365	0	0	0	69,413	0	37,376
6	ACCOUNT 366	PLT366	0	0	0	0	0	30,568
7	ACCOUNT 367	PLT367	0	0	0	42,644	0	22,962
8	ACCOUNT 368	PLT368	0	0	0	44,008	0	66,012
9	ACCOUNT 369	PLT369	0	0	603	0	0	0
10	ACCOUNT 370	PLT370	0	0	9,035	0	0	0
11	ACCOUNT 373	PLT373	0	0	0	3,973,928	0	0
12	OVERHEAD DISTRIBUTION PLANT IN SERVICE	OHDIST	0	0	0	69,413	0	37,376
13	UNDERGROUND DISTRIBUTION PLT IN SERVICE	UGDIST	0	0	0	0	0	30,568
14	TOTAL O&M EXCLUDING GENERAL	OMXGENL	1,000,754	0	0	112,402	0	0
15	TOTAL O&M EXCLUDING GENERAL	OMXGENL	0	0	1,178	0	0	97,139
16	LABOR ACCOUNTS 581-589	LAB58189	0	0	0	43,992	0	23,688
17	LABOR ACCOUNTS 581-589	LAB58189		0	989		0	1,604
18	LABOR ACCOUNTS 591-598	LAB59198	0	0	0	48,202	0	0
19	LABOR ACCOUNTS 591-598	LAB59198		0	3		0	622
31	LABOR CUSTOMER ACCOUNT EXPENSE	LAB900			23,344			89,480
32	RATIO TABLE							
33	DEMAND RELATED							
34	DEMAND - PRODUCTION RELATED							
35	DEMAND PRODUCTION	DPROD	0.0423	0.0000	0.0000	0.0016	0.0000	0.0000
36	DEMAND - TRANSMISSION RELATED							
37	DEMAND TRANSMISSION	DTRAN	0.0423	0.0000	0.0000	0.0016	0.0000	0.0000
38	DEMAND TRANSMISSION	DTRAN	0.0423	0.0000	0.0000	0.0016	0.0000	0.0000
39	DEMAND - DISTRIBUTION RELATED							
40	DIST - PRI DIST SUBSTATIONS	DDISPSUB	0.0000	0.0000	0.0000	0.0017	0.0000	0.0000
41	DIST - POLES TOWERS & FIXTURES	DDISPOLE	0.0000	0.0000	0.0000	0.0007	0.0000	0.0010
42	DIST - OVERHEAD CONDUCTORS	DDISTCON	0.0000	0.0000	0.0000	0.0011	0.0000	0.0006
43	DIST - UNDERGROUND CONDUIT	DDISTUCON	0.0000	0.0000	0.0000	0.0000	0.0000	0.0017
44	DIST - SEC UNDERGROUND DEVICES	DDISTUDEV	0.0000	0.0000	0.0000	0.0011	0.0000	0.0006
45	DIST - LINE TRANSFORMERS	DDISTLINET	0.0000	0.0000	0.0000	0.0007	0.0000	0.0010
46	DIST - STREET LIGHTING	DDISTLTG	0.0000	0.0000	0.0000	1.0000	0.0000	0.0000
47	DIST - CUSTOMER DEPOSITS	DCUSTDEP	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
48	DIST - CUSTOMER ADVANCES	DCUSTADV	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
49	DIST - UNCOLLECTIBLES	DEUNCOL	0.0458	0.0000	0.0000	0.0073	0.0000	0.0000
	ENERGY RELATED							
50	ENERGY PRODUCTION PWR SUPPLY	EFUEL	0.0000	0.0579	0.0000	0.0000	0.0018	0.0000
51	ENERGY PRODUCTION	EPROD	0.0423	0.0000	0.0000	0.0016	0.0000	0.0000
52	ENERGY - SYSTEM BENEFIT RELATED							
53	**ENERGY PRODUCTION PWR SUPPLY-DESIGN**	**EFUELRD**	**0.0000**	**0.0540**	**0.0000**	**0.0000**	**0.0005**	**0.0000**

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FOR THE TEST PERIOD ENDING DECEMBER 31, 2014

Line No.	ALLOCATION FACTOR TABLE Description	Allocation	LARGE POWER SERVCIE DEMAND	LARGE POWER SERVCIE ENERGY	LARGE POWER SERVCIE CUSTOMER	LIGHTING DEMAND	LIGHTING ENERGY	LIGHTING CUSTOMER
	UNWEIGHTED CUSTOMER BILLS	CUSTWGT	0.0000	0.0000	0.0000	0.0000	0.0000	0.0251
1	CUSTOMER SUPERVISION	CSUPV	0.0000	0.0000	0.0000	0.0122	0.0000	0.0007
2	CUSTOMER INFORMATION	DCUSINFO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0251
3	CUSTOMER INFORMATION	CCUSINFO	0.0000	0.0000	0.0000	0.0122	0.0000	0.0007
4	METER READING	CREAD	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
5	CUSTOMER DELIVERY	CUST	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
6	BILLING AND COLLECTION	CBILLCOL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0251
7	CUSTOMER ACCOUNTING	CACCT	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
8	METERS	CMETERS	0.0000	0.0000	0.0012	0.0000	0.0000	0.0000
9	STREET LIGHTING	CLIGHT	0.0000	0.0000	0.0000	0.0000	0.0000	1.0000
10	INTERNALLY DEVELOPED							
11	PLANT IN SERVICE EXCL GENERAL DEMAND	PISXGENL	0.0140	0.0000	0.0000	0.0087	0.0000	0.0004
12	PLANT IN SERVICE EXCL GENERAL CUST	PISXGENL	0.0000	0.0000	0.0001	0.0000	0.0000	0.0015
13	TOTAL PLANT IN SERVICE DEMCUST	TOTPIS	0.0077	0.0000	0.0064	0.0050	0.0000	0.0042
14	TOTAL PLANT IN SERVICE DEMAND	TOTPIS	0.0140	0.0000	0.0000	0.0087	0.0000	0.0004
15	PRODUCTION PLANT IN SERVICE	PRODPIS	0.0423	0.0000	0.0000	0.0016	0.0000	0.0000
16	TRANSMISSION PLANT IN SERVICE	TRANPIS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
17	DISTRIBUTION PLANT IN SERVICE DEMAND	DISTPIS	0.0000	0.0000	0.0000	0.0224	0.0000	0.0000
18	DISTRIBUTION PLANT IN SERVICE DEMAND &CUST	DISTPIS	0.0000	0.0000	0.0000	0.0122	0.0000	0.0007
19	TOTAL TRANSMISSION & DISTRIBUTION	TDPLT	0.0000	0.0000	0.0000	0.0224	0.0000	0.0000
20	GENERAL PLANT	GENLPIS	0.0140	0.0000	0.0000	0.0087	0.0000	0.0004
21	GENERAL PLANT	GENLPIS	0.0000	0.0000	0.0001	0.0000	0.0000	0.0015
22	BASE RATE SALES REVENUE	SALESREV	0.0579	0.0000	0.0000	0.0018	0.0000	0.0000
23	MISC. SERVICE REVENUE ACCT 451				0			0
24	TOTAL O&M LESS FUEL & PP	OM	0.0140	0.0000	0.0000	0.0087	0.0000	0.0004
25	ACCOUNT 360	PLT360	0.0000	0.0000	0.0000	0.0017	0.0000	0.0000
26	ACCOUNT 361	PLT361	0.0000	0.0000	0.0000	0.0017	0.0000	0.0000
27	ACCOUNT 362	PLT362	0.0000	0.0000	0.0000	0.0017	0.0000	0.0000
28	ACCOUNT 364	PLT364	0.0000	0.0000	0.0000	0.0007	0.0000	0.0010
29	ACCOUNT 365	PLT365	0.0000	0.0000	0.0000	0.0011	0.0000	0.0006
30	ACCOUNT 366	PLT366	0.0000	0.0000	0.0000	0.0000	0.0000	0.0017
31	ACCOUNT 367	PLT367	0.0000	0.0000	0.0000	0.0011	0.0000	0.0006
32	ACCOUNT 368	PLT368	0.0000	0.0000	0.0000	0.0007	0.0000	0.0010
33	ACCOUNT 369	PLT369	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
34	ACCOUNT 370	PLT370	0.0000	0.0000	0.0012	0.0000	0.0000	0.0000
35	ACCOUNT 373	PLT373	0.0000	0.0000	0.0000	1.0000	0.0000	0.0000
36	OVERHEAD DISTRIBUTION PLANT IN SERVICE	OHDIST	0.0000	0.0000	0.0000	0.0011	0.0000	0.0006
37	UNDERGROUND DISTRIBUTION PLT IN SERVICE	UGDIST	0.0000	0.0000	0.0000	0.0000	0.0000	0.0017
38	TOTAL O&M EXCLUDING GENERAL	OMXGENL	0.0373	0.0000	0.0000	0.0042	0.0000	0.0000
39	TOTAL O&M EXCLUDING GENERAL	OMXGENL	0.0000	0.0000	0.0002	0.0000	0.0000	0.0145
40	LABOR ACCOUNTS 581-589	LAB58189	0.0000	0.0000	0.0000	0.0011	0.0000	0.0006
41	LABOR ACCOUNTS 581-589	LAB58189	0.0000	0.0000	0.0006	0.0000	0.0000	0.0009
42	LABOR ACCOUNTS 591-598	LAB59198	0.0000	0.0000	0.0000	0.0355	0.0000	0.0000
43	LABOR ACCOUNTS 591-598	LAB59198	0.0000	0.0000	0.0000	0.0000	0.0000	0.0017
44	PROPOSED TAX EXPENSE	TOTPIS	0.0077	0.0000	0.0064	0.0050	0.0000	0.0042
45	LABOR 902-910	LAB9029100	0.0140	0.0000	0.0000	0.0087	0.0000	0.0004
46	LABOR CUSTOMER ACCOUNT EXPENSE	LAB900	0.0000	0.0000	0.0051	0.0000	0.0000	0.0196

Schedule

„H„

UNS Electric, Inc.
Summary of Revenues by Customer Classifications
Adjusted Present Rates And Proposed Rates
Test Period Ended December 31, 2014

Line No.	Class of Service	Test Year Present Net Revenue	Net Change	Proposed % Increase to Test Year	Adjusted TY Revenue	Proposed Dollar Increase (a)	Proposed Percent Increase to Adjusted Test Year Revenues (a)	Proposed Net Revenue
1	Residential Service	$83,768,709	$10,285,000	12.3%	$73,653,026	$20,556,648	27.91%	$94,209,675
2	Small General Service	12,922,488	1,646,999	12.7%	11,905,151	2,664,336	22.38%	14,569,488
3	Interruptible Power Service	2,920,047	268,734	9.2%	2,995,250	193,531	6.46%	3,188,781
4	Medium General Serive	0	41,891,473	0.0%	0	41,891,473	0.0%	41,891,473
5	Large General Service	46,292,475	-37,652,628	-81.3%	41,503,527	-32,857,483	-79.17%	8,646,044
6	Large Power Service	21,454,373	-14,929,822	-69.6%	16,576,681	-9,973,005	-60.16%	6,603,676
7	Lighting	528,359	90,242	17.1%	543,010	75,592	13.92%	618,601
8	Subtotal	$167,886,452	$1,599,999	0.95%	$147,176,645	$22,551,092	15.32%	$169,727,738
9	Other Operating Revenue	1,734,044	95,034	N/A	1,829,078	N/A	N/A	1,829,078
10	Total	$169,620,496	$1,695,033	1.00%	$149,005,723	$22,551,092	15.13%	$171,556,815

Total Electric Retail Service
(a) H-2 (P2)

Recap Schedules
A-1

UNS Electric, Inc.
Comparisons of Revenues by Rate Schedules
Present And Proposed Rates
Test Period Ended December 31, 2014

Line No.	Class of Service	Rate Schedule Present	Proposed [1]	Actual kWh Sales	Actual Average Number of Customers	Actual Average kWh per Customer	Test Year End Sales Adjustments	Adjusted kWh Sales	Adjusted Average Number of Customers	Adjusted Average Sales per Customer	Tariff Changes kWh Sales	Tariff Changes Average Number of Customers	Tariff Changes Average Sales per Customer
1	Residential Cares	CARES	NC	57,138,737	6,112	9,349	1,701,588	58,840,325	6,236	9,436	58,840,325	6,236	9,436
2	Residential Service	RES-01	NC	755,005,617	75,847	9,954	6,209,782	761,215,400	76,035	10,011	761,215,400	76,035	10,011
3	Residential Service TOU	RES-TOU	NC	2,731,217	230	11,892	321,911	3,053,127	257	11,880	3,053,127	257	11,880
4	Res Bright Community Solar	RES-BC	NC	844,333	79	10,733	0	844,333	79	10,733	844,333	79	10,733
5	Residential Unbilled			(484,060)	0			0	0		0	0	
6	Small General Service	SGS-10	NC	118,754,401	8,704	13,643	(253,035)	118,501,366	8,750	13,543	118,501,366	8,750	13,543
7	Small General Service TOU	SGS-TOU	NC	170,628	8	22,750	11,802	182,430	8	22,804	182,430	8	22,804
8	Interruptible Power Service	IPS	NC	38,106,302	32	1,193,931	(2,538,461)	35,567,841	29	1,226,477	35,567,841	29	1,226,477
9	Medium General Service		MGS	0	0	0	0	0	0	0	408,462,296	1,331	306,884
10	Medium General Service TOU		MGS-TOU	0	0	0	0	0	0	0	7,718,956	8	964,869
11	Large General Service	LGS	LGS	448,678,574	1,361	329,688	(2,896,080)	445,782,493	1,341	332,425	95,412,304	17	5,612,488
12	Large General Service TOU	LGS-TOU	LGS TOU	3,834,211	5	821,617	3,884,745	7,718,956	8	964,869	15,418,264	2	7,709,132
13	LGS Bright Community Solar	LGS-BC	MGSBC	16,769	3	5,590	(16,769)	0	0	0	0	0	0
14	Large General Service Unbilled			384,473	0			0	0		0	0	
15	Large Power Service & TOU <69 kV	LPS/LPS TOU	LGS/LGS TOU	92,705,606	12	7,672,188	(19,195,235)	73,510,371	9	8,167,819	0	0	0
16	LPS Standard/Mining & TOU >69 kV	LPS/LPSM/ LPS TOU	NC	157,107,744	6	26,184,624	(64,342,470)	92,765,274	4	23,191,318	92,765,274	4	23,191,318
17	Large Power Service Unbilled			(369,148)	0			0	0		0	0	
18	Lighting	LTG	NC	2,820,013	2,388	1,181	7,237	2,827,250	2,388	1,184	2,827,250	2,388	1,184
19	Total Electric Retail Service			1,677,445,418	94,785	17,697	(77,104,986)	1,600,809,167	95,144	16,825	1,600,809,167	95,144	16,825

Note:
[1] NC equals No Change

UNS Electric, Inc.
Comparisons of Revenues by Rate Schedules
Present And Proposed Rates
Test Period Ended December 31, 2014

Line No.	Class of Service	Proposed	Unadjusted [1] Margin Revenue	Unadjusted [2] Fuel & PPFAC Revenue	Margin Pro Forma Adjustment	Fuel & PPFAC [3] Pro Forma Adjustment	Adjusted Margin Revenue	Adjusted Fuel & PPFAC Revenue	Adjusted TY Revenues	Proposed Revenue	Proposed Increase To TY Revenue $	Proposed Increase To TY Revenue %	Proposed Increase to Adjusted Revenue [4] $	Proposed Increase to Adjusted Revenue [4] %
1	Residential Cares	RES-01	$1,779,128	$3,029,378	$14,612	($503,059)	$1,793,740	$2,526,318	$4,320,058	$5,437,298	$628,793	13.08%	$1,117,240	20.55%
2	Residential Service	RES-01	31,759,612	46,999,721	-289,767	-9,502,250	31,469,845	37,497,471	68,967,316	88,319,110	9,559,778	12.14%	19,351,794	21.91%
3	Residential Service TOU	RES-TOU	116,271	152,725	11,729	-2,326	128,000	150,399	278,400	344,719	75,723	28.15%	66,319	19.24%
4	Res Bright Community Solar	RES-BC	34,190	53,651	-588	0	33,602	53,651	87,253	108,548	20,707	23.57%	21,295	19.62%
5	Residential Unbilled		110,955	-266,920	-110,955	266,920	0	0	0	0	0	0.00%	0	0.00%
6	Small General Service	SGS-10	6,255,704	6,650,173	-128,102	-889,821	6,127,602	5,760,351	11,887,953	14,549,732	1,643,856	12.74%	2,661,779	18.29%
7	Small General Service TOU	SGS-TOU	8,527	8,085	465	121	8,992	8,206	17,198	19,755	3,144	18.93%	2,557	12.94%
8	Interruptible Power Service	IPS	1,335,391	1,584,656	-112,156	187,359	1,223,235	1,772,015	2,995,250	3,188,781	268,734	9.20%	193,531	6.07%
9	Medium General Service	MGS	0	0	0	0	0	0	0	41,268,575	41,268,575	n/a	41,268,575	100.00%
10	Medium General Service TOU	MGS-TOU	0	0	0	0	0	0	0	622,898	622,898	n/a	622,898	100.00%
11	LGS Bright Community Solar	LGS-BC	898	976	-898	-976	0	0	0	0	0	0.00%	0	0.00%
12	Large General Service	LGS	21,574,476	24,416,757	-471,036	-4,630,843	21,103,440	19,785,914	40,889,354	7,351,450	(38,639,783)	-84.02%	(33,537,904)	-456.21%
13	Large General Service TOU	LGS - TOU	121,380	186,059	133,252	173,481	254,632	359,541	614,173	1,294,594	987,155	321.09%	680,421	52.56%
14	General Service Unbilled		138,446	-146,516	-138,446	146,516	0	0	0	0	0	0.00%	0	0.00%
15	Large Power Service & LPS TOU <69 kV	LPS <69	5,072,348	3,652,261	-1,258,960	1,735,527	3,813,388	5,387,788	9,201,176	0	(8,724,609)	-100.00%	(9,201,176)	0.00%
16	Large Power Service Unbilled		-31,928	-47,197	31,928	47,197	0	0	0	0	0	0.00%	0	0.00%
17	Large Power Service & LPS TOU >69 kV	LPS >69	6,894,832	5,914,057	-3,702,992	-1,730,391	3,191,840	4,183,666	7,375,505	6,603,676	(6,205,212)	-48.44%	(771,829)	-11.69%
18	Lighting	LTG	505,944	22,415	0	14,650	505,944	37,065	543,010	618,601	90,242	17.08%	75,592	12.22%
19	Total Electric Service		$75,676,172	$92,210,280	-$6,021,912	-$14,687,894	$69,654,260	$77,522,386	$147,176,645	$169,727,738	$1,599,999	0.95%	$22,551,092	15.32%

Note:
[1] Test Year Billed Margin Revenues calculated $69,916 more than Booked Revenues.
[2] Test Year Billed Fuel and PPFAC revenues calculated $175,930 less than Booked Revenues.
[3] Test Fuel and PPFAC Test Year True-up includes a Billed to Book adjustment of $175,930.
[4] Total increase is $69,916 less than Schedule A1, Line 10 due to difference from Test Year billed to booked revenues.

	Present Rate	Proposed Rate	Increase $	Increase %
Residential Service CARES				
Basic Service Charge	$4.90	$9.00	$4.10	83.67%
Energy Charge 1st 400 kWhs	$0.018973	$0.030810	$0.011837	62.39%
Energy Charge, all additional kWhs	$0.035400	$0.050810	$0.015410	43.53%
Base Power Supply Charge, all kWhs	$0.061700	$0.049260	-$0.012440	-20.16%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Residential Service				
Basic Service Charge	$10.00	$20.00	$10.00	100.00%
Energy Charge 1st 400 kWhs	$0.019300	$0.030810	$0.011510	59.64%
Energy Charge 401-1,000 kWhs	$0.034350	$0.050810	$0.016460	47.92%
Energy Charge, all additional kWhs	$0.038499	$0.050810	$0.012311	31.98%
Base Power Supply Charge, all kWhs	$0.064510	$0.049260	-$0.015250	-23.64%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Residential Service Demand				
Basic Service Charge	N/A	$20.00	N/A	N/A
Demand Charge, 1st 7 kW	N/A	$6.00	N/A	N/A
Demand Charge, all additional kW	N/A	$9.95	N/A	N/A
Energy Charge (kWhs)	N/A	$0.010000	N/A	N/A
Base Power Supply Charge, all kWhs	N/A	$0.049260	N/A	N/A
PPFAC[1]	N/A	$0.000000	N/A	N/A
Residential Service Time-of-Use				
Basic Service Charge	$11.50	$20.00	$8.50	73.91%
Energy Charge 1st 400 kWhs	$0.030350	$0.030810	$0.000460	1.52%
Energy Charge 401-1,000 kWhs	$0.030350	$0.050810	$0.020460	67.41%
Energy Charge, all additional kWhs	$0.030350	$0.050810	$0.020460	67.41%
Base Power Supply Charge				
Summer On-peak, kWh	$0.129605	$0.101110	-$0.028495	-21.99%
Summer Off-peak, kWh	$0.039605	$0.033900	-$0.005705	-14.40%
Winter On-peak, kWh	$0.129605	$0.098960	-$0.030645	-23.64%
Winter Off-peak, kWh	$0.031385	$0.033579	$0.002194	6.99%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Residential Service Demand Time-of-Use				
Basic Service Charge	N/A	$20.00	N/A	N/A
Demand Charge, 1st 7 kW	N/A	$6.00	N/A	N/A
Demand Charge, all additional kW	N/A	$9.95	N/A	N/A
Energy Charge (kWhs)	N/A	$0.010000	N/A	N/A
Base Power Supply Charge				
Summer On-peak, kWh	N/A	$0.101110	N/A	N/A
Summer Off-peak, kWh	N/A	$0.033900	N/A	N/A
Winter On-peak, kWh	N/A	$0.098960	N/A	N/A
Winter Off-peak, kWh	N/A	$0.033579	N/A	N/A
PPFAC[1]	N/A	$0.000000	N/A	N/A
Residential Service Time-of-Use Super Peak				
Basic Service Charge	$11.50	$20.00	$8.50	73.91%
Energy Charge 1st 400 kWhs	$0.025000	$0.030810	$0.005810	23.24%
Energy Charge, all additional kWhs	$0.035000	$0.050810	$0.015810	45.17%
Base Power Supply Charge				
Summer On-peak, kWh	$0.170000	$0.149700	-$0.020300	-11.94%
Summer Off-peak, kWh	$0.039700	$0.038250	-$0.001450	-3.65%
Winter On-peak, kWh	$0.150000	$0.149700	-$0.000300	-0.20%
Winter Off-peak, kWh	$0.038700	$0.038250	-$0.000450	-1.16%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%

	Present Rate	Proposed Rate	Increase $	Increase %
Small General Service				
Basic Service Charge	$14.50	$30.00	$15.50	106.90%
Energy Charge 1st 400 kWh	$0.030176	$0.039497	$0.009321	30.89%
Energy Charge 401 -7,500 kWh	$0.041042	$0.049497	$0.008455	20.60%
Energy Charge >7,500 kWh	$0.076042	$0.086950	$0.010908	14.34%
Base Power Supply Charge, all kWhs	$0.058241	$0.048610	-$0.009631	-16.54%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Small General Service Demand				
Basic Service Charge	N/A	$30.00	N/A	N/A
Demand Charge, 1st 15 kW	N/A	$6.85	N/A	N/A
Demand Charge, all additional kW	N/A	$7.85	N/A	N/A
Energy Charge, 1st 7,500 kWhs	N/A	$0.011100	N/A	N/A
Energy Charge, all additional kWhs	N/A	$0.055000	N/A	N/A
Base Power Supply Charge, all kWhs	N/A	$0.048610	N/A	N/A
PPFAC[1]	N/A	$0.000000	N/A	N/A
Small General Service Time-of-Use				
Basic Service Charge	$16.50	$30.00	$13.50	81.82%
Energy Charge 1st 400 kWh	$0.030176	$0.039497	$0.009321	30.89%
Energy Charge 401 -7,500 kWh	$0.043176	$0.049497	$0.006321	14.64%
Energy Charge >7,500 kWh	$0.076042	$0.086950	$0.010908	14.34%
Base Power Supply Charges				
Summer On-peak, kWh	$0.129605	$0.126510	-$0.003095	-2.39%
Summer Off-peak, kWh	$0.039605	$0.033010	-$0.006595	-16.65%
Winter On-peak, kWh	$0.129605	$0.108510	-$0.021095	-16.28%
Winter Off-peak, kWh	$0.031385	$0.032910	$0.001525	4.86%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Small General Service Demand Time-of-Use				
Basic Service Charge	N/A	$30.00	N/A	N/A
Demand Charge, 1st 15 kW	N/A	$6.85	N/A	N/A
Demand Charge, all additional kW	N/A	$7.85	N/A	N/A
Energy Charge, 1st 7,500 kWhs	N/A	$0.011100	N/A	N/A
Energy Charge, all additional kWhs	N/A	$0.055000	N/A	N/A
Base Power Supply Charge				
Summer On-peak, kWh	N/A	$0.126510	N/A	N/A
Summer Off-peak, kWh	N/A	$0.033010	N/A	N/A
Winter On-peak, kWh	N/A	$0.108510	N/A	N/A
Winter Off-peak, kWh	N/A	$0.032910	N/A	N/A
PPFAC[1]	N/A	$0.000000	N/A	N/A
Medium General Service[2]				
Basic Service Charge	$50.00	$100.00	$50.00	100.00%
Demand Charge, per kW	$12.81	$13.05	$0.24	1.87%
Energy Charge (kWhs)	$0.005470	$0.005500	$0.000030	0.55%
Base Power Supply Charge, all kWhs	$0.056603	$0.048440	-$0.008163	-14.42%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Medium General Service Time-of-Use[2]				
Basic Service Charge	$52.00	$100.00	$48.00	92.31%
Demand Charge, per kW	$12.81	$13.05	$0.24	1.87%
Energy Charge (kWhs)	$0.005470	$0.005500	$0.000030	0.55%
Base Power Supply Charge				
Summer On-peak, kWh	$0.114886	$0.109900	-$0.004986	-4.34%
Summer Off-peak, kWh	$0.039886	$0.033500	-$0.006386	-16.01%
Winter On-peak, kWh	$0.114886	$0.089900	-$0.024986	-21.75%
Winter Off-peak, kWh	$0.026168	$0.031600	$0.005432	20.76%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%

	Present Rate	Proposed Rate	Increase $	Increase %
Large General Service				
Basic Service Charge	$50.00	$300.00	$250.00	500.00%
Demand Charge, per kW	$12.81	$12.96	$0.15	1.17%
Energy Charge (kWhs)	$0.005470	$0.005400	-$0.000070	-1.28%
Base Power Supply Charge, all kWhs	$0.056603	$0.048400	-$0.008203	-14.49%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Large General Service Time-of-Use				
Basic Service Charge	$52.00	$300.00	$248.00	476.92%
Demand Charge, per kW	$12.81	$12.96	$0.15	1.17%
Energy Charge (kWhs)	$0.005470	$0.005400	-$0.000070	-1.28%
Base Power Supply Charge				
Summer On-peak, kWh	$0.114886	$0.145510	$0.030624	26.66%
Summer Off-peak, kWh	$0.039886	$0.034510	-$0.005376	-13.48%
Winter On-peak, kWh	$0.114886	$0.124510	$0.009624	8.38%
Winter Off-peak, kWh	$0.026168	$0.032910	$0.006742	25.76%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Large Power Service[3]				
Basic Service Charge <69 kV	$1,200.00	$300.00	-$900.00	-75.00%
Basic Service Charge ≥69 kV	$1,200.00	$1,200.00	$0.00	0.00%
Demand Charge <69kV, per kW	$22.00	$12.96	-$9.04	-41.09%
Demand Charge ≥69kV, per kW	$17.00	$12.48	-$4.52	-26.59%
Energy Charge (kWhs) <69 kV	$0.000462	$0.005400	$0.004938	1068.83%
Energy Charge (kWhs) ≥69 kV	$0.000462	$0.000520	$0.000058	12.55%
Base Power Supply Charge, all kWhs <69 kV	$0.041880	$0.048400	$0.006520	15.57%
Base Power Supply Charge, all kWhs ≥69 kV	$0.041880	$0.048410	$0.006530	15.59%
PPFAC[1] <69kV	($0.002139)	$0.000000	$0.002139	100.00%
PPFAC[1] ≥69kV	($0.002139)	$0.000000	$0.002139	100.00%
Large Power Service Time-of-Use[3]				
Basic Service Charge <69 kV	$1,200.00	$300.00	-$900.00	-75.00%
Basic Service Charge ≥69 kV	$1,200.00	$1,200.00	$0.00	0.00%
Demand Charge <69kV, per kW	$22.00	$12.96	-$9.04	-41.09%
Demand Charge ≥69kV, per kW	$17.00	$12.48	-$4.52	-26.59%
Energy Charge (kWhs) <69 kV	$0.000462	$0.005400	$0.004938	1068.83%
Energy Charge (kWhs) ≥69 kV	$0.000462	$0.000520	$0.000058	12.55%
Base Power Supply Charge <69 kV				
Summer On-peak, kWh	$0.123580	$0.145510	$0.021930	17.75%
Summer Off-peak, kWh	$0.024716	$0.034510	$0.009794	39.63%
Winter On-peak, kWh	$0.093880	$0.124510	$0.030630	32.63%
Winter Off-peak, kWh	$0.022105	$0.032910	$0.010805	48.88%
Base Power Supply Charge ≥69 kV				
Summer On-peak, kWh	$0.123580	$0.122510	-$0.001070	-0.87%
Summer Off-peak, kWh	$0.024716	$0.032110	$0.007394	29.92%
Winter On-peak, kWh	$0.093880	$0.092110	-$0.001770	-1.89%
Winter Off-peak, kWh	$0.022105	$0.030910	$0.008805	39.83%
PPFAC[1] <69kV	($0.002139)	$0.000000	$0.002139	100.00%
PPFAC[1] ≥69kV	($0.002139)	$0.000000	$0.002139	100.00%
Large Power Service Mining (≥69kV)				
Basic Service Charge	$1,200.00	$1,200.00	$0.00	0.00%
Demand Charge, per kW	$17.00	$12.48	-$4.52	-26.59%
Energy Charge (kWhs)	$0.000462	$0.000520	$0.000058	12.55%
Base Power Supply Charge, all kWhs	$0.041880	$0.048410	$0.006530	15.59%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%

	Present Rate	Proposed Rate	Increase $	Increase %
Interruptible Power Service				
Basic Service Charge	$18.00	$75.00	$57.00	316.67%
Demand Charge, per kW	$5.00	$6.52	$1.52	30.40%
Energy Charge (kWhs)	$0.019408	$0.019790	$0.000382	1.97%
Base Power Supply Charge, all kWhs	$0.043760	$0.049821	$0.006061	13.85%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Lighting Dusk to Dawn				
New 30' Wood Pole (Class 6) - Overhead	$4.34	$4.68	$0.34	7.83%
New 30' Metal or Fiberglass - Overhead	$8.66	$9.35	$0.69	7.97%
Existing Wood Pole - Underground	$2.18	$2.35	$0.17	7.80%
New 30' Wood Pole (Class 6) - Underground	$6.52	$7.04	$0.52	7.98%
New 30' Metal or Fiberglass - Underground	$10.81	$11.67	$0.86	7.96%
Wattage, per Watt	$0.051681	$0.060516	$0.008835	17.10%
Lighting Base Power Supply Charge, per kWh	$0.010113	$0.013110	$0.002997	29.64%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
TOU - Medium General Service Schools (Formally TOU - Small General Service Schools)				
Basic Service Charge	$16.50	$100.00	$83.50	506.06%
Demand Charge, per kW	N/A	$13.05	N/A	N/A
Energy Charge 1st 400 kWh	$0.030176	$0.005500	-$0.024676	-81.77%
Energy Charge 401 -7,500 kWh	$0.043176	$0.005500	-$0.037676	-87.26%
Energy Charge >7,500 kWh	$0.076042	$0.005500	-$0.070542	-92.77%
Base Power Supply Charge				
Summer On-peak, kWh	$0.137405	$0.115600	-$0.021805	-15.87%
Summer Off-peak, kWh	$0.047405	$0.039200	-$0.008205	-17.31%
Winter On-peak, kWh	$0.137405	$0.095600	-$0.041805	-30.42%
Winter Off-peak, kWh	$0.039185	$0.037300	-$0.001885	-4.81%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
TOU - Large General Service Schools				
Basic Service Charge	$52.00	$300.00	$248.00	476.92%
Demand Charge, per kW	$12.81	$12.96	$0.15	1.17%
Energy Charge (kWhs)	$0.005470	$0.005400	-$0.000070	-1.28%
Base Power Supply Charge				
Summer On-peak, kWh	$0.120586	$0.150210	$0.029624	24.57%
Summer Off-peak, kWh	$0.045586	$0.039210	-$0.006376	-13.99%
Winter On-peak, kWh	$0.120586	$0.129210	$0.008624	7.15%
Winter Off-peak, kWh	$0.031868	$0.037610	$0.005742	18.02%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%

[1] The Present Rate for the PPFAC is the Test Year average PPFAC, since the rate varies by month. The Proposed Rate is $0.00, since the PPFAC rate will be reset to zero for one month when the new base rates become effective. However, the PPFAC rate will change monthly in all subsequent months by an amount defined in the proposed PPFAC POA. The Company has proposed the PPFAC be a percentage based adjustment that will be recalculated monthly and reflected as a single percentage based adjustment applied to base fuel cost for each rate class (e.g. the percentage adjustment will be the same percentage value regardless of the rate class).

[2] For the new Medium General Service and Medium General Service Time-of-Use rates, the Present Rate column is populated with the currently existing rates for Large General Service and Large General Service Time-of-Use, respectively, since these two new Medium General Service classes will be comparable to the former Large General Service classes.

[3] The proposed Large Power Service rate classes will be restricted to customers with ≥69kV service. The Proposed Rate column for <69kV service is populated with the Proposed Rates from the corresponding Large General Service rate classes.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE

BILL IMPACTS CURRENT RATES

	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill
		0-400	401-1,000	1,000+	$10.00	$0.019300	$0.034350	$0.038499	$0.001140	$0.064510	-$0.002139	
Xsmall	111	111	0	0	$10.00	$2.14	$0.00	$0.00	$0.13	$7.16	-$0.24	$19.19
Small	330	330	0	0	$10.00	$6.37	$0.00	$0.00	$0.38	$21.29	-$0.71	$37.33
Medium	664	400	264	0	$10.00	$7.72	$9.07	$0.00	$0.76	$42.83	-$1.42	$68.96
Large	1,144	400	600	144	$10.00	$7.72	$20.61	$5.54	$1.30	$73.80	-$2.45	$116.53
Xlarge	2,162	400	600	1,162	$10.00	$7.72	$20.61	$44.74	$2.46	$139.47	-$4.63	$220.37
Mean	830	400	430	0	$10.00	$7.72	$14.75	$0.00	$0.95	$53.51	-$1.77	$85.16
Sum	983	400	583	0	$10.00	$7.72	$20.04	$0.00	$1.12	$63.43	-$2.10	$100.20
Win	669	400	269	0	$10.00	$7.72	$9.25	$0.00	$0.76	$43.18	-$1.43	$69.48
Annual												$1,018.12

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
		0-400	401-1,000	1,000+	$20.00	$0.030810	$0.050810	$0.050810	$0.000000	$0.049260	$0.000000			
Xsmall	111	111	0	0	$20.00	$3.42	$0.00	$0.00	$0.00	$5.47	$0.00	$28.89	$9.70	50.5%
Small	330	330	0	0	$20.00	$10.17	$0.00	$0.00	$0.00	$16.26	$0.00	$46.43	$9.09	24.4%
Medium	664	400	264	0	$20.00	$12.32	$13.41	$0.00	$0.00	$32.71	$0.00	$78.45	$9.49	13.8%
Large	1,144	400	600	144	$20.00	$12.32	$30.49	$7.32	$0.00	$56.35	$0.00	$126.48	$9.95	8.5%
Xlarge	2,162	400	600	1,162	$20.00	$12.32	$30.49	$59.04	$0.00	$106.50	$0.00	$228.35	$7.98	3.6%
Mean	830	400	430	0	$20.00	$12.32	$21.82	$0.00	$0.00	$40.86	$0.00	$95.01	$9.85	11.6%
Sum	983	400	583	0	$20.00	$12.32	$29.64	$0.00	$0.00	$48.44	$0.00	$110.40	$10.20	10.2%
Win	669	400	269	0	$20.00	$12.32	$13.69	$0.00	$0.00	$32.98	$0.00	$78.99	$9.51	13.7%
Annual												$1,136.37	$118.26	11.6%

RESIDENTIAL SERVICE DEMAND

Full Requirements Service

	BILL IMPACTS PROPOSED RATES - RES-01																	
	Load Factor	Demand (kW)	Total kWh	Delivery (kW)		Delivery (kWh)			Basic Service Charge	Delivery 0-7 kW	Delivery 7+ kW	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill
				0-7	Over 7	0-400	401-1,000	1,000+	$20.00	$0.00	$0.00	$0.030810	$0.050810	$0.050810	$0.000000	$0.049260	$0.000000	
Xsmall	0.18	0.8	111	0.8	-	111	0	0	$20.00	$0.00	$0.00	$3.42	$0.00	$0.00	$0.00	$5.47	$0.00	$28.89
Small	0.19	2.3	330	2.3	-	330	0	0	$20.00	$0.00	$0.00	$10.17	$0.00	$0.00	$0.00	$16.26	$0.00	$46.43
Medium	0.22	4.1	664	4.1	-	400	264	0	$20.00	$0.00	$0.00	$12.32	$13.41	$0.00	$0.00	$32.71	$0.00	$78.45
Large	0.25	6.3	1,144	6.3	-	400	600	144	$20.00	$0.00	$0.00	$12.32	$30.49	$7.32	$0.00	$56.35	$0.00	$126.48
Xlarge	0.27	11.0	2,162	7.0	4.0	400	600	1,162	$20.00	$0.00	$0.00	$12.32	$30.49	$59.04	$0.00	$106.50	$0.00	$228.35
Mean	0.23	5.1	830	5.1	-	400	430	0	$20.00	$0.00	$0.00	$12.32	$21.82	$0.00	$0.00	$40.86	$0.00	$95.01
Sum	0.26	5.2	983	5.2	-	400	583	0	$20.00	$0.00	$0.00	$12.32	$29.64	$0.00	$0.00	$48.44	$0.00	$110.40
Win	0.19	4.9	669	4.9	-	400	269	0	$20.00	$0.00	$0.00	$12.32	$13.69	$0.00	$0.00	$32.98	$0.00	$78.99
Annual																		$1,136.37

	BILL IMPACTS PROPOSED RATES																			
	Load Factor	Demand (kW)	Total kWh	Delivery (kW)		Delivery (kWh)			Basic Service Charge	Delivery 0-7 kW	Delivery 7+ kW	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				0-7	7+	0-400	401-1,000	1,000+	$20.00	$6.00	$9.95	$0.01000	$0.01000	$0.01000	$0.000000	$0.049260	$0.000000			
Xsmall	0.18	0.8	111	0.8	-	111	0	0	$20.00	$4.80	$0.00	$1.11	$0.00	$0.00	$0.00	$5.47	$0.00	$31.38	$2.49	8.6%
Small	0.19	2.3	330	2.3	-	330	0	0	$20.00	$13.80	$0.00	$3.30	$0.00	$0.00	$0.00	$16.26	$0.00	$53.36	$6.93	14.9%
Medium	0.22	4.1	664	4.1	-	400	264	0	$20.00	$24.60	$0.00	$4.00	$2.64	$0.00	$0.00	$32.71	$0.00	$83.95	$5.50	7.0%
Large	0.25	6.3	1,144	6.3	-	400	600	144	$20.00	$37.80	$0.00	$4.00	$6.00	$1.44	$0.00	$56.35	$0.00	$125.59	-$0.89	-0.7%
Xlarge	0.27	11.0	2,162	7.0	4.0	400	600	1,162	$20.00	$42.00	$39.80	$4.00	$6.00	$11.62	$0.00	$106.50	$0.00	$229.92	$1.57	0.7%
Mean	0.23	5.1	830	5.1	-	400	430	0	$20.00	$30.60	$0.00	$4.00	$4.30	$0.00	$0.00	$40.86	$0.00	$99.76	$4.75	5.0%
Sum	0.26	5.2	983	5.2	-	400	583	0	$20.00	$31.20	$0.00	$4.00	$5.83	$0.00	$0.00	$48.44	$0.00	$109.47	-$0.93	-0.8%
Win	0.19	4.9	669	4.9	-	400	269	0	$20.00	$29.40	$0.00	$4.00	$2.69	$0.00	$0.00	$32.98	$0.00	$89.07	$10.08	12.8%
Annual																		$1,191.28	$54.91	4.8%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

RESIDENTIAL SERVICE DEMAND

Partial Requirements Service

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Energy Use (kWh)	Energy Produced (kWh)	Net Energy Delivered (kWh)	Net Energy Received (kbh)	Billed Energy (kWh)	Delivery (kW)		Delivery (kWh)			Basic Service Charge	Delivery 0-7 kW	Delivery 7+ kW	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Energy Production Credits	Net Bill	$ Change	% Change
								0-7	7+	0-400	401-1,000	1,000+	$10.00	$0.00	$0.00	$0.019300	$0.034350	$0.038499	$0.001140	$0.064510	-$0.002139				
Xsmall	0.18	0.8	111	111	71	71	0	0.8	-	0	0	0	$10.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$10.00		
Small	0.19	2.3	330	330	190	190	0	2.3	-	0	0	0	$10.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$10.00		
Medium	0.23	4.0	664	664	364	364	0	4.0	-	0	0	0	$10.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$10.00		
Large	0.26	6.1	1,144	1,144	612	612	0	6.1	-	0	0	0	$10.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$10.00		
Xlarge	0.27	10.9	2,162	2,162	1,159	1,159	0	7.0	3.9	0	0	0	$10.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$10.00		
Mean	0.23	5.0	830	830	458	458	0	5.0	-	0	0	0	$10.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$10.00		
Sum	0.26	5.2	995	932	518	436	0	5.2	-	0	0	0	$10.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$10.00		
Win	0.19	4.8	665	728	398	480	0	4.8	-	0	0	0	$10.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$10.00		
Annual																							$120.00		
Changes from Current Full Requirements RES-01 Annual Bill																								-$898.12	-88%

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Energy Use (kWh)	Energy Produced (kWh)	Net Energy Delivered (kWh)	Net Energy Received (kbh)	Billed Energy (kWh)	Delivery (kW)		Delivery (kWh)			Basic Service Charge	Delivery 0-7 kW	Delivery 7+ kW	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Energy Production Credits	Net Bill	$ Change	% Change
								0-7	7+	0-400	401-1,000	1,000+	$20.00	$6.00	$9.95	$0.01000	$0.01000	$0.01000	$0.000000	$0.049260	$0.000000	$0.058400			
Xsmall	0.18	0.8	111	111	71	71	71	0.8	-	71	0	0	$20.00	$4.80	$0.00	$0.71	$0.00	$0.00	$0.00	$3.50	$0.00	($4.15)	$24.86	$14.86	148.6%
Small	0.19	2.3	330	330	190	190	190	2.3	-	190	0	0	$20.00	$13.80	$0.00	$1.90	$0.00	$0.00	$0.00	$9.36	$0.00	($11.10)	$33.96	$23.96	239.6%
Medium	0.23	4.0	664	664	364	364	364	4.0	-	364	0	0	$20.00	$24.00	$0.00	$3.64	$0.00	$0.00	$0.00	$17.93	$0.00	($21.26)	$44.31	$34.31	343.1%
Large	0.26	6.1	1,144	1,144	612	612	612	6.1	-	400	212	0	$20.00	$36.60	$0.00	$4.00	$2.12	$0.00	$0.00	$30.15	$0.00	($35.74)	$57.13	$47.13	471.3%
Xlarge	0.27	10.9	2,162	2,162	1,159	1,159	1,159	7.0	3.9	400	600	159	$20.00	$42.00	$38.81	$4.00	$6.00	$1.59	$0.00	$57.09	$0.00	($67.69)	$101.80	$91.80	918.0%
Mean	0.23	5.0	830	830	458	458	458	5.0	-	400	58	0	$20.00	$30.00	$0.00	$4.00	$0.58	$0.00	$0.00	$22.56	$0.00	($26.75)	$50.39	$40.39	403.9%
Sum	0.26	5.2	995	932	518	436	518	5.2	-	400	118	0	$20.00	$31.20	$0.00	$4.00	$1.18	$0.00	$0.00	$25.52	$0.00	($25.46)	$56.44	$46.44	464.4%
Win	0.19	4.8	665	728	398	480	398	4.8	-	398	0	0	$20.00	$28.80	$0.00	$3.98	$0.00	$0.00	$0.00	$19.61	$0.00	($28.03)	$44.36	$34.36	343.6%
Annual																							$604.77	$484.77	404.0%
Change from Proposed Full Requirements RES-01 Annual Bill																								-$531.60	-46.8%

Notes: 1. This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

3. Partial Requirements Service customers are assumed to own a distributed generation facility sized to produce energy equal to 100% of usage on an annual basis.

4. Partial Requirements Service customers taking service under the current Net Metering tariff are allowed to bank kWh produced in excess of kWh consumed and credit the excess production against usage in future months. Therefore, Billed Energy for the average summer and winter months is represented as zero under Current Rates.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE CARES

	BILL IMPACTS CURRENT RATES										
	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery 0-400 kWh	Delivery 400+ kWh	TCA	Base Fuel	PPFAC	Net Bill	Discounts
		1-400	401+	$4.90	$0.018973	$0.035400	$0.001140	$0.061700	-$0.002139		
Xsmall	220	220	0	$4.90	$4.17	$0.00	$0.25	$13.57	-$0.47	$15.69	30.00%
Small	360	360	0	$4.90	$6.83	$0.00	$0.41	$22.21	-$0.77	$26.86	20.00%
Medium	607	400	207	$4.90	$7.59	$7.33	$0.69	$37.45	-$1.30	$50.99	10.00%
Large	990	400	590	$4.90	$7.59	$20.89	$1.13	$61.08	-$2.12	$84.12	10.00%
Xlarge	1,843	400	1,443	$4.90	$7.59	$51.08	$2.10	$113.71	-$3.94	$167.44	$8.00
Mean	753	400	353	$4.90	$7.59	$12.49	$0.86	$46.45	-$1.61	$63.61	10.00%
Sum	867	400	467	$4.90	$7.59	$16.53	$0.99	$53.49	-$1.85	$73.49	10.00%
Win	638	400	238	$4.90	$7.59	$8.43	$0.73	$39.37	-$1.37	$53.69	10.00%
Annual										$763.08	

	BILL IMPACTS PROPOSED RATES												
	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery 0-400 kWh	Delivery 400+ kWh	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change	
		1-400	401+	$9.00	$0.030810	$0.050810	$0.000000	$0.049260	$0.000000				
Xsmall	220	220	0	$9.00	$6.78	$0.00	$0.00	$10.84	$0.00	$18.63	$2.94	18.76%	30.00%
Small	360	360	0	$9.00	$11.09	$0.00	$0.00	$17.73	$0.00	$30.26	$3.40	12.64%	20.00%
Medium	607	400	207	$9.00	$12.32	$10.52	$0.00	$29.90	$0.00	$55.57	$4.58	8.97%	10.00%
Large	990	400	590	$9.00	$12.32	$29.98	$0.00	$48.77	$0.00	$90.06	$5.94	7.06%	10.00%
Xlarge	1,843	400	1,443	$9.00	$12.32	$73.32	$0.00	$90.79	$0.00	$177.43	$9.99	5.97%	$8.00
Mean	753	400	353	$9.00	$12.32	$17.93	$0.00	$37.09	$0.00	$68.71	$5.10	8.01%	10.00%
Sum	867	400	467	$9.00	$12.32	$23.73	$0.00	$42.71	$0.00	$78.98	$5.49	7.48%	10.00%
Win	638	400	238	$9.00	$12.32	$12.10	$0.00	$31.43	$0.00	$58.37	$4.68	8.71%	10.00%
Annual										$824.09	$61.01	8.00%	

RESIDENTIAL SERVICE CARES MEDICAL

	BILL IMPACTS CURRENT RATES										
	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery 0-400 kWh	Delivery 400+ kWh	TCA	Base Fuel	PPFAC	Net Revenue	Discounts
		1-400	401+	$4.90	$0.018973	$0.035400	$0.001140	$0.061700	-$0.002139		
Xsmall	365	365	0	$4.90	$6.93	$0.00	$0.42	$22.52	-$0.78	$23.79	30.00%
Small	564	400	164	$4.90	$7.59	$5.81	$0.64	$34.80	-$1.21	$36.77	30.00%
Medium	878	400	478	$4.90	$7.59	$16.92	$1.00	$54.17	-$1.88	$66.16	20.00%
Large	1,340	400	940	$4.90	$7.59	$33.28	$1.53	$82.68	-$2.87	$114.40	10.00%
Xlarge	2,304	400	1,904	$4.90	$7.59	$67.40	$2.63	$142.16	-$4.93	$211.75	$8.00
Mean	1,034	400	634	$4.90	$7.59	$22.43	$1.18	$63.78	-$2.21	$78.13	20.00%
sum	1,199	400	799	$4.90	$7.59	$28.28	$1.37	$73.97	-$2.56	$90.84	20.00%
win	871	400	471	$4.90	$7.59	$16.68	$0.99	$53.75	-$1.86	$65.64	20.00%
Annual										$938.88	

	BILL IMPACTS PROPOSED RATES												
	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery 0-400 kWh	Delivery 400+ kWh	TCA	Base Fuel	PPFAC	Net Revenue	$ Change	% Change	
		1-400	401+	$9.00	$0.030810	$0.050810	$0.000000	$0.049260	$0.000000				
Xsmall	365	365	0	$9.00	$11.25	$0.00	$0.00	$17.98	$0.00	$26.76	$2.97	12.5%	30.00%
Small	564	400	164	$9.00	$12.32	$8.33	$0.00	$27.78	$0.00	$40.20	$3.43	9.3%	30.00%
Medium	878	400	478	$9.00	$12.32	$24.29	$0.00	$43.25	$0.00	$71.09	$4.93	7.4%	20.00%
Large	1,340	400	940	$9.00	$12.32	$47.76	$0.00	$66.01	$0.00	$121.58	$7.18	6.3%	10.00%
Xlarge	2,304	400	1,904	$9.00	$12.32	$96.74	$0.00	$113.50	$0.00	$223.56	$11.81	5.6%	$8.00
Mean	1,034	400	634	$9.00	$12.32	$32.20	$0.00	$50.92	$0.00	$83.55	$5.42	6.9%	20.00%
sum	1,199	400	799	$9.00	$12.32	$40.59	$0.00	$59.05	$0.00	$96.77	$5.93	6.5%	20.00%
win	871	400	471	$9.00	$12.32	$23.94	$0.00	$42.91	$0.00	$70.54	$4.90	7.5%	20.00%
Annual										$1,003.82	$64.94	6.9%	

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+	$11.50	$0.030350	$0.001140			-$0.002139	
	Winter	0.24	0.76							$0.129605	$0.031385		
	Summer									$0.129605	$0.039605		
Xsm	150	36	114	150	0	0	$11.50	$4.55	$0.17	$4.67	$3.58	-$0.32	$24.15
Small	286	69	217	286	0	0	$11.50	$8.68	$0.33	$8.90	$6.82	-$0.61	$35.62
Medium	641	154	487	400	241	0	$11.50	$19.45	$0.73	$19.94	$15.29	-$1.37	$65.54
Large	1,043	250	793	400	600	43	$11.50	$31.66	$1.19	$32.44	$24.88	-$2.23	$99.44
XLg	1,810	434	1,376	400	600	810	$11.50	$54.93	$2.06	$56.30	$43.17	-$3.87	$164.09
AnnAvg	1,008	242	766	400	600	8	$11.50	$30.59	$1.15	$31.36	$24.05	-$2.16	$96.49
Avg Win	801	192	608	400	401	0	$11.50	$24.30	$0.91	$24.90	$19.10	-$1.71	$79.00

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill		
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+				$0.000000			
	Winter						$20.00	$0.030810	$0.050810	$0.050810	$0.000000	$0.098960	$0.033579				
	Summer											$0.101110	$0.033900			$ Change	% Change
Xsm	150	36	114	150	0	0	$20.00	$4.62	$0.00	$0.00	$0.00	$3.56	$3.83	$0.00	$32.01	$7.86	32.55%
Small	286	69	217	286	0	0	$20.00	$8.81	$0.00	$0.00	$0.00	$6.79	$7.30	$0.00	$42.90	$7.28	20.44%
Medium	641	154	487	400	241	0	$20.00	$12.32	$12.25	$0.00	$0.00	$15.22	$16.36	$0.00	$76.15	$10.61	16.19%
Large	1,043	250	793	400	600	43	$20.00	$12.32	$30.49	$2.18	$0.00	$24.77	$26.62	$0.00	$116.38	$16.94	17.04%
XLg	1,810	434	1,376	400	600	810	$20.00	$12.32	$30.49	$41.16	$0.00	$42.99	$46.19	$0.00	$193.15	$29.06	17.71%
AnnAvg	1,008	242	766	400	600	8	$20.00	$12.32	$30.49	$0.41	$0.00	$23.94	$25.73	$0.00	$112.89	$16.40	17.00%
Avg Win	801	192	608	400	401	0	$20.00	$12.32	$20.36	$0.00	$0.00	$19.02	$20.43	$0.00	$92.13	$13.13	16.62%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE DEMAND

WINTER

BILL IMPACTS PROPOSED RATES RES-TOU

	Load Factor	Demand (kW)	Energy (kWh)	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery (kWh) TIERS			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
				On-Peak	Off-Peak	0-400	401-1,000	1,000+	$20.00	0-400	401-1,000	1,000+	$0.00000			$0.000000	
			Winter	0.24	0.76					$0.030810	$0.050810	$0.050810		$0.098960	$0.033579		
			Summer											$0.101110	$0.033900		
Xsm	0.18	1.2	150	36	114	150	0	0	$20.00	$4.62	$0.00	$0.00	$0.00	$3.56	$3.83	$0.00	$32.01
Small	0.17	2.3	286	69	217	286	0	0	$20.00	$8.81	$0.00	$0.00	$0.00	$6.79	$7.30	$0.00	$42.90
Medium	0.19	4.7	641	154	487	400	241	0	$20.00	$12.32	$12.25	$0.00	$0.00	$15.22	$16.36	$0.00	$76.15
Large	0.21	6.9	1,043	250	793	400	600	43	$20.00	$12.32	$30.49	$2.18	$0.00	$24.77	$26.62	$0.00	$116.38
XLg	0.22	11.3	1,810	434	1,376	400	600	810	$20.00	$12.32	$30.49	$41.16	$0.00	$42.99	$46.19	$0.00	$193.15
AnnAvg	0.23	6.1	1,008	242	766	400	600	8	$20.00	$12.32	$30.49	$0.41	$0.00	$23.94	$25.73	$0.00	$112.89
Avg Win	0.19	5.8	801	192	608	400	401	0	$20.00	$12.32	$20.36	$0.00	$0.00	$19.02	$20.43	$0.00	$92.13

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Energy (kWh)	Delivery (kW)		Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery (kW)		Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill		
				0-7	Over 7	On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-7	Over 7	0-400	401-1,000	1,000+				$0.00000			
			Winter								$20.00	$6.00	$9.95	$0.010000	$0.010000	$0.010000	$0.000000	$0.098960	$0.033579				
			Summer															$0.101110	$0.033900			$ Change	% Change
Xsm	0.18	1.2	150	1.2	-	36	114	150	0	0	$20.00	$7.20	$0.00	$1.50	$0.00	$0.00	$0.00	$3.56	$3.83	$0.00	$36.09	$4.08	12.75%
Small	0.17	2.3	286	2.3	-	69	217	286	0	0	$20.00	$13.80	$0.00	$2.86	$0.00	$0.00	$0.00	$6.79	$7.30	$0.00	$50.75	$7.85	18.30%
Medium	0.19	4.7	641	4.7	-	154	487	400	241	0	$20.00	$28.20	$0.00	$4.00	$2.41	$0.00	$0.00	$15.22	$16.36	$0.00	$86.19	$10.04	13.18%
Large	0.21	6.9	1,043	6.9	-	250	793	400	600	43	$20.00	$41.40	$0.00	$4.00	$6.00	$0.43	$0.00	$24.77	$26.62	$0.00	$123.22	$6.84	5.88%
XLg	0.22	11.3	1,810	7.0	4.3	434	1,376	400	600	810	$20.00	$42.00	$42.79	$4.00	$6.00	$8.10	$0.00	$42.99	$46.19	$0.00	$212.07	$18.92	9.79%
AnnAvg	0.23	6.1	1,008	6.1	-	242	766	400	600	8	$20.00	$36.60	$0.00	$4.00	$6.00	$0.08	$0.00	$23.94	$25.73	$0.00	$116.35	$3.46	3.06%
Avg Win	0.19	5.8	801	5.8	-	192	608	400	401	0	$20.00	$34.80	$0.00	$4.00	$4.01	$0.00	$0.00	$19.02	$20.43	$0.00	$102.26	$10.13	11.00%

Notes: 1. This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

RESIDENTIAL SERVICE RATE TIME OF USE

SUMMER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh	TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+	$11.50	$0.030350	$0.001140			-$0.002139	
	Winter									$0.129605	$0.031385		
	Summer	0.23	0.77							$0.129605	$0.039605		
Xsm	261	60	201	261	0	0	$11.50	$7.92	$0.30	$7.78	$7.96	-$0.56	$34.90
Small	525	121	404	400	125	0	$11.50	$15.93	$0.60	$15.65	$16.01	-$1.12	$58.57
Medium	983	226	757	400	583	0	$11.50	$29.83	$1.12	$29.30	$29.98	-$2.10	$99.63
Large	1,611	371	1,240	400	600	611	$11.50	$48.89	$1.84	$48.02	$49.13	-$3.45	$155.93
XLg	2,681	617	2,064	400	600	1,681	$11.50	$81.37	$3.06	$79.92	$81.76	-$5.74	$251.87
AnnAvg	1,008	232	776	400	600	8	$11.50	$30.59	$1.15	$30.05	$30.74	-$2.16	$101.87
Avg Sum	1,195	275	920	400	600	195	$11.50	$36.26	$1.36	$35.61	$36.43	-$2.56	$118.60

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill		
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+				$0.000000			
	Winter						$20.00	$0.030810	$0.050810	$0.050810	$0.000000	$0.098960	$0.033579				
	Summer											$0.101110	$0.033900			$ Change	% Change
Xsm	261	60	201	261	0	0	$20.00	$8.04	$0.00	$0.00	$0.00	$6.07	$6.81	$0.00	$40.92	$6.02	17.24%
Small	525	121	404	400	125	0	$20.00	$12.32	$6.35	$0.00	$0.00	$12.21	$13.70	$0.00	$64.58	$6.01	10.27%
Medium	983	226	757	400	583	0	$20.00	$12.32	$29.62	$0.00	$0.00	$22.86	$25.66	$0.00	$110.46	$10.83	10.87%
Large	1,611	371	1,240	400	600	611	$20.00	$12.32	$30.49	$31.04	$0.00	$37.46	$42.05	$0.00	$173.36	$17.43	11.18%
XLg	2,681	617	2,064	400	600	1,681	$20.00	$12.32	$30.49	$85.41	$0.00	$62.35	$69.98	$0.00	$280.55	$28.68	11.38%
AnnAvg	1,008	232	776	400	600	8	$20.00	$12.32	$30.49	$0.41	$0.00	$23.44	$26.31	$0.00	$112.97	$11.10	10.89%
Avg Sum	1,195	275	920	400	600	195	$20.00	$12.32	$30.49	$9.89	$0.00	$27.78	$31.19	$0.00	$131.67	$13.07	11.02%

	Net Bill	$ Change	% Change
Current Annual	$1,185.62		
Proposed Annual	$1,342.80	$157.18	13.26%

RESIDENTIAL SERVICE RATE TIME OF USE DEMAND

SUMMER

BILL IMPACTS PROPOSED RATES RES-TOU

	Load Factor	Demand (kW)	Energy (kWh)	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
				On-Peak	Off-Peak	0-400	401-1,000	1,000+	$20.00	0-400	401-1,000	1,000+	$0.00000			$0.000000	
			Winter							$0.030810	$0.050810	$0.050810		$0.098960	$0.033579		
			Summer	0.23	0.77									$0.101110	$0.033900		
Xsm	0.19	1.9	261	60	201	261	0	0	$20.00	$8.04	$0.00	$0.00	$0.00	$6.07	$6.81	$0.00	$40.92
Small	0.22	3.3	525	121	404	400	125	0	$20.00	$12.32	$6.35	$0.00	$0.00	$12.21	$13.70	$0.00	$64.58
Medium	0.26	5.2	983	226	757	400	583	0	$20.00	$12.32	$29.62	$0.00	$0.00	$22.86	$25.66	$0.00	$110.46
Large	0.29	7.6	1,611	371	1,240	400	600	611	$20.00	$12.32	$30.49	$31.04	$0.00	$37.46	$42.05	$0.00	$173.36
XLg	0.32	11.7	2,681	617	2,064	400	600	1,681	$20.00	$12.32	$30.49	$85.41	$0.00	$62.35	$69.98	$0.00	$280.55
AnnAvg	0.23	6.1	1,008	232	776	400	600	8	$20.00	$12.32	$30.49	$0.41	$0.00	$23.44	$26.31	$0.00	$112.97
Avg Sum	0.26	6.4	1,195	275	920	400	600	195	$20.00	$12.32	$30.49	$9.89	$0.00	$27.78	$31.19	$0.00	$131.67

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Energy (kWh)	Delivery (kW)		Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery (kW)		Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
				0-7	Over 7	On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-7	Over 7	0-400	401-1,000	1,000+				$0.00000			
			Winter															$0.098960	$0.033579				
			Summer								$20.00	$6.00	$9.95	$0.010000	$0.010000	$0.010000	$0.000000	$0.101110	$0.033900				
Xsm	0.19	1.9	261	1.9	-	60	201	261	0	0	$20.00	$11.40	$0.00	$2.61	$0.00	$0.00	$0.00	$6.07	$6.81	$0.00	$46.89	$5.97	14.59%
Small	0.22	3.3	525	3.3	-	121	404	400	125	0	$20.00	$19.80	$0.00	$4.00	$1.25	$0.00	$0.00	$12.21	$13.70	$0.00	$70.96	$6.38	9.88%
Medium	0.26	5.2	983	5.2	-	226	757	400	583	0	$20.00	$31.20	$0.00	$4.00	$5.83	$0.00	$0.00	$22.86	$25.66	$0.00	$109.55	-$0.91	-0.82%
Large	0.29	7.6	1,611	7.0	0.6	371	1,240	400	600	611	$20.00	$42.00	$5.97	$4.00	$6.00	$6.11	$0.00	$37.46	$42.05	$0.00	$163.59	-$9.77	-5.64%
XLg	0.32	11.7	2,681	7.0	4.7	617	2,064	400	600	1,681	$20.00	$42.00	$46.77	$4.00	$6.00	$16.81	$0.00	$62.35	$69.98	$0.00	$267.91	-$12.65	-4.51%
AnnAvg	0.23	6.1	1,008	6.1	-	232	776	400	600	8	$20.00	$36.60	$0.00	$4.00	$6.00	$0.08	$0.00	$23.44	$26.31	$0.00	$116.43	$3.46	3.06%
Avg Sum	0.26	6.4	1,195	6.4	-	275	920	400	600	195	$20.00	$38.40	$0.00	$4.00	$6.00	$1.95	$0.00	$27.78	$31.19	$0.00	$129.32	-$2.35	-1.78%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

	Net Bill	$ Change	% Change
Current Annual	$1,342.80		
Proposed Annual	$1,389.48	$46.68	3.48%

RESIDENTIAL SERVICE RATE TIME OF USE - SUPER PEAK

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+					
	Winter	0.1	0.9				$11.50	$0.025000	$0.035000	$0.035000	$0.001140	$0.150000	$0.038700	-$0.002139	
	Summer											$0.170000	$0.039700		
Xsm	150	15	135	150	0	0	$11.50	$3.75	$0.00	$0.00	$0.17	$2.25	$5.22	-$0.32	$22.57
Small	286	29	257	286	0	0	$11.50	$7.15	$0.00	$0.00	$0.33	$4.29	$9.96	-$0.61	$32.62
Medium	641	64	577	400	241	0	$11.50	$10.00	$8.44	$0.00	$0.73	$9.62	$22.33	-$1.37	$61.25
Large	1,043	104	939	400	600	43	$11.50	$10.00	$21.00	$1.51	$1.19	$15.65	$36.33	-$2.23	$94.95
XLg	1,810	181	1,629	400	600	810	$11.50	$10.00	$21.00	$28.35	$2.06	$27.15	$63.04	-$3.87	$159.23
AnnAvg	1,008	101	907	400	600	8	$11.50	$10.00	$21.00	$0.28	$1.15	$15.12	$35.11	-$2.16	$92.00
Avg Win	801	80	721	400	401	0	$11.50	$10.00	$14.02	$0.00	$0.91	$12.01	$27.89	-$1.71	$74.62

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+							
	Winter						$20.00	$0.030810	$0.050810	$0.050810	$0.000000	$0.149700	$0.038250	$0.000000			
	Summer											$0.149700	$0.038250				
Xsm	150	15	135	150	0	0	$20.00	$4.62	$0.00	$0.00	$0.00	$2.25	$5.16	$0.00	$32.03	$9.46	41.91%
Small	286	29	257	286	0	0	$20.00	$8.81	$0.00	$0.00	$0.00	$4.28	$9.85	$0.00	$42.94	$10.32	31.64%
Medium	641	64	577	400	241	0	$20.00	$12.32	$12.25	$0.00	$0.00	$9.60	$22.07	$0.00	$76.24	$14.99	24.47%
Large	1,043	104	939	400	600	43	$20.00	$12.32	$30.49	$2.18	$0.00	$15.61	$35.91	$0.00	$116.51	$21.56	22.71%
XLg	1,810	181	1,629	400	600	810	$20.00	$12.32	$30.49	$41.16	$0.00	$27.10	$62.31	$0.00	$193.38	$34.15	21.45%
AnnAvg	1,008	101	907	400	600	8	$20.00	$12.32	$30.49	$0.41	$0.00	$15.09	$34.70	$0.00	$113.01	$21.01	22.84%
AvgWin	801	80	721	400	401	0	$20.00	$12.32	$20.36	$0.00	$0.00	$11.99	$27.56	$0.00	$92.23	$17.61	23.60%

RESIDENTIAL SERVICE RATE TIME OF USE - SUPER PEAK

SUMMER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+				-$0.002139	
	Winter						$11.50	$0.025000	$0.035000	$0.035000	$0.001140	$0.150000	$0.038700		
	Summer	0.14	0.86									$0.170000	$0.039700		
Xsm	261	37	224	261	0	0	$11.50	$6.53	$0.00	$0.00	$0.30	$6.21	$8.91	-$0.56	$32.89
Small	525	74	452	400	125	0	$11.50	$10.00	$4.38	$0.00	$0.60	$12.50	$17.92	-$1.12	$55.78
Medium	983	138	845	400	583	0	$11.50	$10.00	$20.41	$0.00	$1.12	$23.40	$33.56	-$2.10	$97.89
Large	1,611	226	1,385	400	600	611	$11.50	$10.00	$21.00	$21.39	$1.84	$38.34	$55.00	-$3.45	$155.62
XLg	2,681	375	2,306	400	600	1,681	$11.50	$10.00	$21.00	$58.84	$3.06	$63.81	$91.53	-$5.74	$254.00
AnnAvg	1,008	141	867	400	600	8	$11.50	$10.00	$21.00	$0.28	$1.15	$23.99	$34.42	-$2.16	$100.18
AvgSum	1,195	167	1,027	400	600	195	$11.50	$10.00	$21.00	$6.82	$1.36	$28.43	$40.79	-$2.56	$117.34

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill		
		On-Peak	Off-Peak	0-400	401-1,000	1,000+	$20.00	0-400	401-1,000	1,000+				$0.000000			
	Winter							$0.030810	$0.050810	$0.050810	$0.000000	$0.149700	$0.038250				
	Summer	0.14	0.86									$0.149700	$0.038250			$ Change	% Change
Xsm	261	37	224	261	0	0	$20.00	$8.04	$0.00	$0.00	$0.00	$5.47	$8.59	$0.00	$42.10	$9.21	28.00%
Small	525	74	452	400	125	0	$20.00	$12.32	$6.35	$0.00	$0.00	$11.00	$17.27	$0.00	$66.94	$11.16	20.01%
Medium	983	138	845	400	583	0	$20.00	$12.32	$29.62	$0.00	$0.00	$20.60	$32.34	$0.00	$114.88	$16.99	17.36%
Large	1,611	226	1,385	400	600	611	$20.00	$12.32	$30.49	$31.04	$0.00	$33.76	$52.99	$0.00	$180.60	$24.98	16.05%
XLg	2,681	375	2,306	400	600	1,681	$20.00	$12.32	$30.49	$85.41	$0.00	$56.19	$88.19	$0.00	$292.60	$38.60	15.19%
AnnAvg	1,008	141	867	400	600	8	$20.00	$12.32	$30.49	$0.41	$0.00	$21.13	$33.16	$0.00	$117.51	$17.33	17.29%
AvgSum	1,195	167	1,027	400	600	195	$20.00	$12.32	$30.49	$9.89	$0.00	$25.04	$39.30	$0.00	$137.04	$19.70	16.78%

	Net Bill	$ Change	% Change
Current Annual	$1,151.78		
Proposed Annual	$1,375.62	$223.84	19.43%

SMALL GENERAL SERVICE

BILL IMPACTS CURRENT RATES

	Total kWh	Delivery kWh			Basic Service Charge	Delivery (kWh)			TCA	Base Fuel	PPFAC	Net Bill
		1-400	401-7500	7501+		1-400	401-7500	7501+				
					$14.50	$0.030176	$0.041042	$0.076042	$0.001140	$0.058241	-$0.002139	
Xsm	200	200	0	0	$14.50	$6.04	$0.00	$0.00	$0.23	$11.65	-$0.43	$31.99
Small	350	350	0	0	$14.50	$10.56	$0.00	$0.00	$0.40	$20.38	-$0.75	$45.09
Medium	561	400	161	0	$14.50	$12.07	$6.61	$0.00	$0.64	$32.67	-$1.20	$65.29
Large	1,447	400	1,047	0	$14.50	$12.07	$42.97	$0.00	$1.65	$84.27	-$3.10	$152.36
XLg	4,078	400	3,678	0	$14.50	$12.07	$150.95	$0.00	$4.65	$237.51	-$8.72	$410.96
Mean	1,131	400	731	0	$14.50	$12.07	$30.00	$0.00	$1.29	$65.87	-$2.42	$121.31
sum	1,277	400	877	0	$14.50	$12.07	$36.00	$0.00	$1.46	$74.39	-$2.73	$135.69
win	980	400	580	0	$14.50	$12.07	$23.82	$0.00	$1.12	$57.10	-$2.10	$106.51
Annual												$1,453.20

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery kWh			Basic Service Charge	Delivery (kWh)			TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
		1-400	401-7500	7501+		1-400	401-7500	7501+						
					$30.00	$0.039497	$0.049497	$0.086950	$0.000000	$0.048610	$0.000000			
Xsm	200	200	0	0	$30.00	$7.90	$0.00	$0.00	$0.00	$9.72	$0.00	$47.62	$15.63	48.85%
Small	350	350	0	0	$30.00	$13.82	$0.00	$0.00	$0.00	$17.01	$0.00	$60.83	$15.74	34.90%
Medium	561	400	161	0	$30.00	$15.80	$7.97	$0.00	$0.00	$27.27	$0.00	$81.04	$15.75	24.12%
Large	1,447	400	1,047	0	$30.00	$15.80	$51.82	$0.00	$0.00	$70.34	$0.00	$167.96	$15.60	10.24%
XLg	4,078	400	3,678	0	$30.00	$15.80	$182.05	$0.00	$0.00	$198.23	$0.00	$426.08	$15.12	3.68%
Mean	1,131	400	731	0	$30.00	$15.80	$36.18	$0.00	$0.00	$54.98	$0.00	$136.96	$15.65	12.90%
sum	1,277	400	877	0	$30.00	$15.80	$43.42	$0.00	$0.00	$62.09	$0.00	$151.31	$15.62	11.51%
win	980	400	580	0	$30.00	$15.80	$28.73	$0.00	$0.00	$47.66	$0.00	$122.19	$15.68	14.72%
Annual												$1,641.00	$187.80	12.92%

SMALL GENERAL SERVICE DEMAND

Full Requirements Service

BILL IMPACTS PROPOSED RATES - SGS-10

	Load Factor	Demand (kW)	Total kWh	Delivery (kW)		Delivery kWh			Basic Service Charge	Delivery (kW)		Delivery (kWh)			TCA	Base Fuel	PPFAC	Net Bill
				0-15	Over 15	1-400	401-7500	7501+	$30.00	0-15	15+	1-400	401-7500	7501+				
										$0.00	$0.00	$0.039497	$0.049497	$0.086950	$0.000000	$0.048610	$0.000000	
Xsm	0.23	1.2	200	1.2	-	200	0	0	$30.00	$0.00	$0.00	$7.90	$0.00	$0.00	$0.00	$9.72	$0.00	$47.62
Small	0.27	1.8	350	1.8	-	350	0	0	$30.00	$0.00	$0.00	$13.82	$0.00	$0.00	$0.00	$17.01	$0.00	$60.83
Medium	0.26	3.0	561	3.0	-	400	161	0	$30.00	$0.00	$0.00	$15.80	$7.97	$0.00	$0.00	$27.27	$0.00	$81.04
Large	0.27	7.3	1,447	7.3	-	400	1,047	0	$30.00	$0.00	$0.00	$15.80	$51.82	$0.00	$0.00	$70.34	$0.00	$167.96
XLg	0.29	19.3	4,078	15.0	4.3	400	3,678	0	$30.00	$0.00	$0.00	$15.80	$182.05	$0.00	$0.00	$198.23	$0.00	$426.08
Mean	0.25	6.1	1,131	6.1	-	400	731	0	$30.00	$0.00	$0.00	$15.80	$36.18	$0.00	$0.00	$54.98	$0.00	$136.96
sum	0.27	6.5	1,277	6.5	-	400	877	0	$30.00	$0.00	$0.00	$15.80	$43.42	$0.00	$0.00	$62.09	$0.00	$151.31
win	0.24	5.6	980	5.6	-	400	580	0	$30.00	$0.00	$0.00	$15.80	$28.73	$0.00	$0.00	$47.66	$0.00	$122.19
Annual																		$1,641.00

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kW)		Delivery kWh			Basic Service Charge	Delivery (kW)		Delivery (kWh)			TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				0-15	Over 15	1-400	401-7500	7501+	$30.00	0-15	15+	1-400	401-7500	7501+						
										$6.85	$7.85	$0.011100	$0.011100	$0.055000	$0.000000	$0.048610	$0.000000			
Xsm	0.23	1.2	200	1.2	-	200	0	0	$30.00	$8.22	$0.00	$2.22	$0.00	$0.00	$0.00	$9.72	$0.00	$50.16	$2.54	5.33%
Small	0.27	1.8	350	1.8	-	350	0	0	$30.00	$12.33	$0.00	$3.89	$0.00	$0.00	$0.00	$17.01	$0.00	$63.23	$2.40	3.95%
Medium	0.26	3.0	561	3.0	-	400	161	0	$30.00	$20.55	$0.00	$4.44	$1.79	$0.00	$0.00	$27.27	$0.00	$84.05	$3.01	3.71%
Large	0.27	7.3	1,447	7.3	-	400	1,047	0	$30.00	$50.01	$0.00	$4.44	$11.62	$0.00	$0.00	$70.34	$0.00	$166.41	-$1.56	-0.93%
XLg	0.29	19.3	4,078	15.0	4.3	400	3,678	0	$30.00	$102.75	$33.76	$4.44	$40.83	$0.00	$0.00	$198.23	$0.00	$410.01	-$16.08	-3.77%
Mean	0.25	6.1	1,131	6.1	-	400	731	0	$30.00	$41.79	$0.00	$4.44	$8.11	$0.00	$0.00	$54.98	$0.00	$139.32	$2.36	1.72%
sum	0.27	6.5	1,277	6.5	-	400	877	0	$30.00	$44.53	$0.00	$4.44	$9.74	$0.00	$0.00	$62.09	$0.00	$150.80	-$0.51	-0.34%
win	0.24	5.6	980	5.6	-	400	580	0	$30.00	$38.36	$0.00	$4.44	$6.44	$0.00	$0.00	$47.66	$0.00	$126.90	$4.71	3.85%
Annual																		$1,666.17	$25.17	1.53%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

SMALL GENERAL SERVICE DEMAND

Partial Requirements Service

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Total kWh	Energy Produced (kWh)	Net Energy Delivered (kWh)	Net Energy Received (kbh)	Billed Energy (kWh)	Delivery (kW)		Delivery kWh			Basic Service Charge	Delivery (kW)		Delivery (kWh)			TCA	Base Fuel	PPFAC	Energy Production Credits	Net Bill
								0-15	Over 15	1-400	401-7500	7501+		0-15	15+	1-400	401-7500	7501+					
													$14.50	$0.00	$0.00	$0.030176	$0.041042	$0.076042	$0.001140	$0.058241	-$0.002139		
Xsm	0.24	1.1	200	200	108	108	0	1.1	-	0	0	0	$14.50	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$14.50
Small	0.28	1.7	350	350	184	184	0	1.7	-	0	0	0	$14.50	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$14.50
Medium	0.25	3.1	561	561	285	285	0	3.1	-	0	0	0	$14.50	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$14.50
Large	0.31	6.5	1,447	1,447	653	653	0	6.5	-	0	0	0	$14.50	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$14.50
XLg	0.34	16.6	4,078	4,078	1,976	1,976	0	15.0	1.6	0	0	0	$14.50	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$14.50
Mean	0.27	5.8	1,131	1,131	575	575	0	5.8	-	0	0	0	$14.50	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$14.50
sum	0.29	6.1	1,277	1,270	629	579	0	6.1	-	0	0	0	$14.50	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$14.50
win	0.25	5.4	980	992	520	570	0	5.4	-	0	0	0	$14.50	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$14.50
Annual																							$174.00

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Energy Produced (kWh)	Net Energy Delivered (kWh)	Net Energy Received (kbh)	Billed Energy (kWh)	Delivery (kW)		Delivery kWh			Basic Service Charge	Delivery (kW)		Delivery (kWh)			TCA	Base Fuel	PPFAC	Energy Production Credits	Net Bill	$ Change	% Change
								0-15	Over 15	1-400	401-7500	7501+		0-15	15+	1-400	401-7500	7501+							
													$30.00	$6.85	$7.85	$0.011100	$0.011100	$0.055000	$0.000000	$0.048610	$0.000000	$0.058400			
Xsm	0.24	1.1	200	200	108	108	108	1.1	-	108	0	0	$30.00	$7.54	$0.00	$1.20	$0.00	$0.00	$0.00	$5.25	$0.00	-$6.31	$37.68	$23.18	159.85%
Small	0.28	1.7	350	350	184	184	184	1.7	-	184	0	0	$30.00	$11.65	$0.00	$2.04	$0.00	$0.00	$0.00	$8.94	$0.00	-$10.75	$41.88	$27.38	188.82%
Medium	0.25	3.1	561	561	285	285	285	3.1	-	285	0	0	$30.00	$21.24	$0.00	$3.16	$0.00	$0.00	$0.00	$13.85	$0.00	-$16.64	$51.60	$37.10	255.87%
Large	0.31	6.5	1,447	1,447	653	653	653	6.5	-	400	253	0	$30.00	$44.53	$0.00	$4.44	$2.81	$0.00	$0.00	$31.74	$0.00	-$38.14	$75.38	$60.88	419.86%
XLg	0.34	16.6	4,078	4,078	1,976	1,976	1,976	15.0	1.6	400	1,576	0	$30.00	$102.75	$12.56	$4.44	$17.49	$0.00	$0.00	$96.05	$0.00	-$115.40	$147.89	$133.39	919.94%
Mean	0.27	5.8	1,131	1,131	575	575	575	5.8	-	400	175	0	$30.00	$39.73	$0.00	$4.44	$1.94	$0.00	$0.00	$27.95	$0.00	-$33.58	$70.48	$55.98	386.07%
sum	0.29	6.1	1,277	1,270	629	579	629	6.1	-	400	229	0	$30.00	$41.79	$0.00	$4.44	$2.54	$0.00	$0.00	$30.58	$0.00	-$33.81	$75.53	$61.03	420.91%
win	0.25	5.4	980	992	520	570	520	5.4	-	400	120	0	$30.00	$36.99	$0.00	$4.44	$1.33	$0.00	$0.00	$25.28	$0.00	-$33.29	$64.75	$50.25	346.57%
Annual																							$841.70	$667.70	383.74%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

3. Partial Requirements Service customers are assumed to own a distributed generation facility sized to produce energy equal to 100% of usage on an annual basis.

4. Partial Requirements Service customers taking service under the current Net Metering tariff are allowed to bank kWh produced in excess of kWh consumed and credit the excess production against usage in future months. Therefore, Billed Energy for the average summer and winter months is represented as zero under Current Rates.

SMALL GENERAL SERVICE RATE TIME OF USE

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+				-$0.002139	
	Winter	0.23					$16.50	$0.030176	$0.043176	$0.076042	$0.001140	$0.129605	$0.031385		
	Summer	0.18										$0.129605	$0.039605		
Xsm	394	91	303	394	0	0	$16.50	$11.87	$0.00	$0.00	$0.45	$11.73	$9.51	-$0.84	$49.22
Small	636	146	490	400	236	0	$16.50	$12.07	$10.19	$0.00	$0.73	$18.96	$15.37	-$1.36	$72.46
Medium	1633	376	1,257	400	1,233	0	$16.50	$12.07	$53.24	$0.00	$1.86	$48.68	$39.46	-$3.49	$168.32
Large	2,328	535	1,793	400	1,928	0	$16.50	$12.07	$83.24	$0.00	$2.65	$69.40	$56.26	-$4.98	$235.14
XLg	3,091	711	2,380	400	2,691	0	$16.50	$12.07	$116.19	$0.00	$3.52	$92.14	$74.70	-$6.61	$308.51
WinAvg	1,551	357	1,194	400	1,151	0	$16.50	$12.07	$49.70	$0.00	$1.77	$46.24	$37.48	-$3.32	$160.44

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+				$0.000000			
	Winter	0.23					$30.00	$0.039497	$0.049497	$0.086950	$0.000000	$0.108510	$0.032910				
	Summer	0.18										$0.126510	$0.033010				
Xsm	394	91	303	394	0	0	$30.00	$15.54	$0.00	$0.00	$0.00	$9.82	$9.97	$0.00	$65.33	$16.11	32.74%
Small	636	146	490	400	236	0	$30.00	$15.80	$11.68	$0.00	$0.00	$15.87	$16.12	$0.00	$89.47	$17.01	23.48%
Medium	1,633	376	1,257	400	1,233	0	$30.00	$15.80	$61.03	$0.00	$0.00	$40.76	$41.38	$0.00	$188.97	$20.65	12.27%
Large	2,328	535	1,793	400	1,928	0	$30.00	$15.80	$95.43	$0.00	$0.00	$58.10	$58.99	$0.00	$258.32	$23.18	9.86%
XLg	3,091	711	2,380	400	2,691	0	$30.00	$15.80	$133.20	$0.00	$0.00	$77.14	$78.33	$0.00	$334.47	$25.96	8.42%
WinAvg	1,551	357	1,194	400	1,151	0	$30.00	$15.80	$56.97	$0.00	$0.00	$38.71	$39.31	$0.00	$180.79	$20.35	12.68%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

SMALL GENERAL SERVICE RATE TIME OF USE DEMAND

WINTER

	BILL IMPACTS PROPOSED RATES SGS-TOU																
	Load Factor	Demand (kW)	Energy (kWh)	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
				On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+				$0.000000	
			Winter	0.23					$30.00	$0.039497	$0.049497	$0.086950	$0.000000	$0.108510	$0.032910		
			Summer	0.18										$0.126510	$0.033010		
Xsm	0.25	2.2	394	91	303	394	0	0	$30.00	$15.54	$0.00	$0.00	$0.00	$9.82	$9.97	$0.00	$65.33
Small	0.27	3.3	636	146	490	400	236	0	$30.00	$15.80	$11.68	$0.00	$0.00	$15.87	$16.12	$0.00	$89.47
Medium	0.20	11.3	1633	376	1,257	400	1,233	0	$30.00	$15.80	$61.03	$0.00	$0.00	$40.76	$41.38	$0.00	$188.97
Large	0.26	12.2	2,328	535	1,793	400	1,928	0	$30.00	$15.80	$95.43	$0.00	$0.00	$58.10	$58.99	$0.00	$258.32
XLg	0.27	15.5	3,091	711	2,380	400	2,691	0	$30.00	$15.80	$133.20	$0.00	$0.00	$77.14	$78.33	$0.00	$334.47
WinAvg	0.24	8.9	1,551	357	1,194	400	1,151	0	$30.00	$15.80	$56.97	$0.00	$0.00	$38.71	$39.31	$0.00	$180.79

	BILL IMPACTS PROPOSED RATES																						
	Load Factor	Demand (kW)	Energy (kWh)	Delivery (kW)		Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery (kW)		Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill		
				0-15	Over 15	On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-15	Over 15	0-400	401-7,500	7,500+				$0.000000		$ Change	% Change
			Winter			0.23					$30.00	$6.85	$7.85	$0.011100	$0.011100	$0.055000	$0.000000	$0.108510	$0.032910				
			Summer			0.18												$0.126510	$0.033010				
Xsm	0.25	2.2	394	2.2	-	91	303	394	0	0	$30.00	$15.07	$0.00	$4.37	$0.00	$0.00	$0.00	$9.82	$9.97	$0.00	$69.23	3.90	0.06
Small	0.27	3.3	636	3.3	-	146	490	400	236	0	$30.00	$22.61	$0.00	$4.44	$2.62	$0.00	$0.00	$15.87	$16.12	$0.00	$91.66	2.19	0.02
Medium	0.20	11.3	1,633	11.3	-	376	1,257	400	1,233	0	$30.00	$77.41	$0.00	$4.44	$13.69	$0.00	$0.00	$40.76	$41.38	$0.00	$207.68	18.71	0.10
Large	0.26	12.2	2,328	12.2	-	535	1,793	400	1,928	0	$30.00	$83.57	$0.00	$4.44	$21.40	$0.00	$0.00	$58.10	$58.99	$0.00	$256.50	-1.82	-0.01
XLg	0.27	15.5	3,091	15.0	0.5	711	2,380	400	2,691	0	$30.00	$102.75	$3.93	$4.44	$29.87	$0.00	$0.00	$77.14	$78.33	$0.00	$326.46	-8.01	-0.02
WinAvg	0.24	8.9	1,551	8.9	-	357	1,194	400	1,151	0	$30.00	$60.97	$0.00	$4.44	$12.78	$0.00	$0.00	$38.71	$39.31	$0.00	$186.21	5.42	0.03

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

SMALL GENERAL SERVICE RATE TIME OF USE

SUMMER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+					
	Winter	0.23					$16.50	$0.030176	$0.043176	$0.076042	$0.001140	$0.129605	$0.031385	-$0.002139	
	Summer	0.18										$0.129605	$0.039605		
Xsm	781	141	640	400	381	0	$16.50	$12.07	$16.45	$0.00	$0.89	$18.22	$25.36	-$1.67	$87.82
Small	1220	220	1,000	400	820	0	$16.50	$12.07	$35.40	$0.00	$1.39	$28.46	$39.62	-$2.61	$130.83
Medium	2350	423	1,927	400	1,950	0	$16.50	$12.07	$84.17	$0.00	$2.68	$54.81	$76.30	-$5.03	$241.50
Large	3,078	554	2,524	400	2,678	0	$16.50	$12.07	$115.63	$0.00	$3.51	$71.81	$99.96	-$6.58	$312.90
XLg	3,640	655	2,985	400	3,240	0	$16.50	$12.07	$139.89	$0.00	$4.15	$84.92	$118.21	-$7.79	$367.95
SumAvg	2,256	406	1,850	400	1,856	0	$16.50	$12.07	$80.15	$0.00	$2.57	$52.64	$73.28	-$4.83	$232.38

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+							
	Winter	0.23					$30.00	$0.039497	$0.049497	$0.086950	$0.000000	$0.108510	$0.032910	$0.000000			
	Summer	0.18										$0.126510	$0.033010				
Xsm	781	141	640	400	381	0	$30.00	$15.80	$18.86	$0.00	$0.00	$17.78	$21.14	$0.00	$103.58	$15.76	17.95%
Small	1,220	220	1,000	400	820	0	$30.00	$15.80	$40.59	$0.00	$0.00	$27.78	$33.02	$0.00	$147.19	$16.36	12.50%
Medium	2,350	423	1,927	400	1,950	0	$30.00	$15.80	$96.49	$0.00	$0.00	$53.50	$63.60	$0.00	$259.39	$17.89	7.41%
Large	3,078	554	2,524	400	2,678	0	$30.00	$15.80	$132.55	$0.00	$0.00	$70.09	$83.32	$0.00	$331.76	$18.86	6.03%
XLg	3,640	655	2,985	400	3,240	0	$30.00	$15.80	$160.37	$0.00	$0.00	$82.89	$98.53	$0.00	$387.59	$19.64	5.34%
SumAvg	2,256	406	1,850	400	1,856	0	$30.00	$15.80	$91.88	$0.00	$0.00	$51.38	$61.08	$0.00	$250.14	$17.76	7.64%

		$ Change	% Change
Current Annual	$2,356.95		
Proposed Annual	$2,585.58	$228.63	9.70%

SMALL GENERAL SERVICE RATE TIME OF USE DEMAND

SUMMER

BILL IMPACTS PROPOSED RATES SGS-TOU

	Load Factor	Demand (kW)	Energy (kWh)	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
				On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+				$0.000000	
			Winter	0.23										$0.108510	$0.032910		
			Summer	0.18					$30.00	$0.039497	$0.049497	$0.086950	$0.000000	$0.126510	$0.033010		
Xsm	0.25	4.3	781	141	640	400	381	0	$30.00	$15.80	$18.86	$0.00	$0.00	$17.78	$21.14	$0.00	$103.58
Small	0.27	6.1	1220	220	1,000	400	820	0	$30.00	$15.80	$40.59	$0.00	$0.00	$27.78	$33.02	$0.00	$147.19
Medium	0.24	13.4	2350	423	1,927	400	1,950	0	$30.00	$15.80	$96.49	$0.00	$0.00	$53.50	$63.60	$0.00	$259.39
Large	0.28	15.1	3,078	554	2,524	400	2,678	0	$30.00	$15.80	$132.55	$0.00	$0.00	$70.09	$83.32	$0.00	$331.76
XLg	0.30	16.4	3,640	655	2,985	400	3,240	0	$30.00	$15.80	$160.37	$0.00	$0.00	$82.89	$98.53	$0.00	$387.59
SumAvg	0.23	13.7	2,256	406	1,850	400	1,856	0	$30.00	$15.80	$91.88	$0.00	$0.00	$51.38	$61.08	$0.00	$250.14

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	kWh	Delivery (kW)		Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery (kW)		Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill		
				0-15	Over 15	On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-15	Over 15	0-400	401-7,500	7,500+				$0.000000			
			Winter			0.23												$0.108510	$0.032910				
			Summer			0.18					$30.00	$6.85	$7.85	$0.011100	$0.011100	$0.055000	$0.000000	$0.126510	$0.033010			$ Change	% Change
Xsm	0.25	4.3	781	4.3	-	141	640	400	381	0	$30.00	$29.46	$0.00	$4.44	$4.23	$0.00	$0.00	$17.78	$21.14	$0.00	$107.05	$3.47	3.35%
Small	0.27	6.1	1,220	6.1	-	220	1,000	400	820	0	$30.00	$41.79	$0.00	$4.44	$9.10	$0.00	$0.00	$27.78	$33.02	$0.00	$146.13	-$1.07	-0.72%
Medium	0.24	13.4	2,350	13.4	-	423	1,927	400	1,950	0	$30.00	$91.79	$0.00	$4.44	$21.64	$0.00	$0.00	$53.50	$63.60	$0.00	$264.97	$5.58	2.15%
Large	0.28	15.1	3,078	15.0	0.1	554	2,524	400	2,678	0	$30.00	$102.75	$0.78	$4.44	$29.73	$0.00	$0.00	$70.09	$83.32	$0.00	$321.12	-$10.65	-3.21%
XLg	0.30	16.4	3,640	15.0	1.4	655	2,985	400	3,240	0	$30.00	$102.75	$10.99	$4.44	$35.96	$0.00	$0.00	$82.89	$98.53	$0.00	$365.56	-$22.03	-5.68%
SumAvg	0.23	13.7	2,256	13.7	-	406	1,850	400	1,856	0	$30.00	$93.85	$0.00	$4.44	$20.61	$0.00	$0.00	$51.38	$61.08	$0.00	$261.36	$11.22	4.48%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

	Net Bill	$ Change	% Change
Current Annual	$2,585.58		
Proposed Annual	$2,685.36	$99.78	3.86%

INTERRUPTIBLE POWER SERVICE

	BILL IMPACTS CURRENT RATES									
	Load Factor	Total kWh	Demand (kW)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill
				$18.00	$5.00	$0.019408	$0.432900	0.043760	-$0.002139	
Xsm	40.3%	1,116	66	$18.00	$331.53	$21.65	$28.70	$48.82	-$2.39	$446.32
Small	27.4%	14,651	108	$18.00	$541.23	$284.34	$46.86	$641.11	-$31.34	$1,500.20
Medium	30.7%	29,389	154	$18.00	$768.97	$570.39	$66.58	$1,286.08	-$62.87	$2,647.15
Large	44.3%	71,334	237	$18.00	$1,183.91	$1,384.44	$102.50	$3,121.55	-$152.61	$5,657.79
XLg	58.4%	384,599	887	$18.00	$4,432.94	$7,464.30	$383.80	$16,830.06	-$822.79	$28,306.31
AnnAvg	56.0%	97,708	239	$18.00	$1,195.06	$1,896.33	$103.47	$4,275.72	-$209.03	$7,279.55
AvgWin	52.0%	83,072	219	$18.00	$1,094.21	$1,612.26	$94.74	$3,635.24	-$177.72	$6,276.73
AvgSum	62.0%	112,958	250	$18.00	$1,247.88	$2,192.29	$108.04	$4,943.03	-$241.65	$8,267.58
Annual										$87,265.86

	BILL IMPACTS PROPOSED RATES											
	Load Factor	Total kWh	Demand (kW)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$75.00	$6.52	$0.019790	$0.000000	$0.049821	$0.000000			
Xsm	40.3%	1,116	66	$75.00	$432.32	$22.08	$0.00	$55.58	$0.00	$584.98	$138.66	31.07%
Small	27.4%	14,651	108	$75.00	$705.77	$289.94	$0.00	$729.91	$0.00	$1,800.62	$300.42	20.03%
Medium	30.7%	29,389	154	$75.00	$1,002.74	$581.61	$0.00	$1,464.20	$0.00	$3,123.55	$476.40	18.00%
Large	44.3%	71,334	237	$75.00	$1,543.81	$1,411.69	$0.00	$3,553.89	$0.00	$6,584.39	$926.60	16.38%
XLg	58.4%	384,599	887	$75.00	$5,780.55	$7,611.22	$0.00	$19,161.00	$0.00	$32,627.77	$4,321.46	15.27%
AnnAvg	56.0%	97,708	239	$75.00	$1,558.36	$1,933.65	$0.00	$4,867.91	$0.00	$8,434.92	$1,155.37	15.87%
AvgWin	52.0%	83,072	219	$75.00	$1,426.84	$1,644.00	$0.00	$4,138.71	$0.00	$7,284.55	$1,007.82	16.06%
AvgSum	62.0%	112,958	250	$75.00	$1,627.23	$2,235.44	$0.00	$5,627.64	$0.00	$9,565.31	$1,297.73	15.70%
Annual										$101,099.20	$13,833.34	15.85%

MEDIUM GENERAL SERVICE

	BILL IMPACTS CURRENT RATES									
	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill
				$50.00	$12.81	$0.005470	$0.432900	$0.056603	-$0.002139	
Xsm	0.46	20	4,040	$50.00	$256.20	$22.10	$8.66	$228.68	-$8.64	$557.00
Small	0.46	20	6,400	$50.00	$256.20	$35.01	$8.66	$362.26	-$13.69	$698.44
Medium	0.46	36	12,160	$50.00	$463.88	$66.52	$15.68	$688.29	-$26.01	$1,258.36
Large	0.46	80	26,880	$50.00	$1,025.41	$147.03	$34.65	$1,521.49	-$57.51	$2,721.07
Xlarge	0.46	294	98,640	$50.00	$3,762.89	$539.56	$127.16	$5,583.32	-$211.02	$9,851.91
AnnAvg	0.46	80	26,796	$50.00	$1,022.22	$146.58	$34.54	$1,516.76	-$57.33	$2,712.77
sum	0.46	90	30,153	$50.00	$1,150.28	$164.94	$38.87	$1,706.76	-$64.51	$3,046.34
win	0.46	70	23,520	$50.00	$897.22	$128.65	$30.32	$1,331.28	-$50.32	$2,387.15
Annual										$32,600.94

	BILL IMPACTS PROPOSED RATES											
	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$100.00	$13.05	$0.005500	$0.000000	$0.048440	$0.000000			
Xsm	0.46	20	4,040	$100.00	$261.00	$22.22	$0.00	$195.70	$0.00	$578.92	$21.92	3.9%
Small	0.46	20	6,400	$100.00	$261.00	$35.20	$0.00	$310.02	$0.00	$706.22	$7.78	1.1%
Medium	0.46	36	12,160	$100.00	$472.57	$66.88	$0.00	$589.03	$0.00	$1,228.48	-$29.88	-2.4%
Large	0.46	80	26,880	$100.00	$1,044.62	$147.84	$0.00	$1,302.07	$0.00	$2,594.53	-$126.54	-4.7%
Xlarge	0.46	294	98,640	$100.00	$3,833.39	$542.52	$0.00	$4,778.12	$0.00	$9,254.03	-$597.88	-6.1%
AnnAvg	0.46	80	26,796	$100.00	$1,041.37	$147.38	$0.00	$1,298.02	$0.00	$2,586.77	-$126.00	-4.6%
sum	0.46	90	30,153	$100.00	$1,171.83	$165.84	$0.00	$1,460.62	$0.00	$2,898.29	-$148.05	-4.9%
win	0.46	70	23,520	$100.00	$914.03	$129.36	$0.00	$1,139.29	$0.00	$2,282.68	-$104.47	-4.4%
Annual										$31,085.82	-$1,515.12	-4.6%

MEDIUM GENERAL SERVICE TIME OF USE

WINTER

BILL IMPACTS CURRENT RATES

	Load Factor	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill
		Winter		0.29		$52.00	$12.81	$0.005470	$0.43290	0.114886	0.026168	-$0.002139	
		Summer		0.20						0.114886	0.039886		
Xsm	0.46	27,974	83	8,112	19,862	$52.00	$1,067.14	$153.02	$36.06	$932.01	$519.74	-$59.85	$2,700.12
Small	0.46	28,067	84	8,139	19,928	$52.00	$1,070.69	$153.53	$36.18	$935.11	$521.46	-$60.04	$2,708.93
Medium	0.46	48,453	144	14,051	34,402	$52.00	$1,848.37	$265.04	$62.46	$1,614.31	$900.22	-$103.66	$4,638.74
Large	0.56	62,572	186	18,146	44,426	$52.00	$2,386.98	$342.27	$80.67	$2,084.71	$1,162.54	-$133.86	$5,975.31
XLg	0.66	193,470	576	56,106	137,364	$52.00	$7,380.44	$1,058.28	$249.41	$6,445.83	$3,594.53	-$413.90	$18,366.59
AnnAvg	0.58	69,713	208	20,217	49,496	$52.00	$2,659.39	$381.33	$89.87	$2,322.62	$1,295.22	-$149.14	$6,651.29
AvgWin	0.56	65,673	196	19,045	46,628	$52.00	$2,505.28	$359.23	$84.66	$2,188.02	$1,220.16	-$140.50	$6,268.85

BILL IMPACTS PROPOSED RATES

	Load Factor	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
		Winter				$100.00	$13.05	$0.005500	$0.00000	0.089900	0.031600	$0.000000			
		Summer								0.109900	0.033500				
Xsm	0.46	27,974	83	8,112	19,862	$100.00	$1,087.14	$153.86	$0.00	$729.31	$627.62	$0.00	$2,697.93	-$2.19	-0.1%
Small	0.46	28,067	84	8,139	19,928	$100.00	$1,090.75	$154.37	$0.00	$731.73	$629.71	$0.00	$2,706.56	-$2.37	-0.1%
Medium	0.46	48,453	144	14,051	34,402	$100.00	$1,883.00	$266.49	$0.00	$1,263.22	$1,087.09	$0.00	$4,599.80	-$38.94	-0.8%
Large	0.56	62,572	186	18,146	44,426	$100.00	$2,431.70	$344.15	$0.00	$1,631.31	$1,403.87	$0.00	$5,911.03	-$64.28	-1.1%
XLg	0.66	193,470	576	56,106	137,364	$100.00	$7,518.71	$1,064.09	$0.00	$5,043.96	$4,340.69	$0.00	$18,067.45	-$299.14	-1.6%
AnnAvg	0.58	69,713	208	20,217	49,496	$100.00	$2,709.21	$383.42	$0.00	$1,817.49	$1,564.08	$0.00	$6,574.20	-$77.09	-1.2%
AvgWin	0.56	65,673	196	19,045	46,628	$100.00	$2,552.21	$361.20	$0.00	$1,712.16	$1,473.44	$0.00	$6,199.01	-$69.84	-1.1%

MEDIUM GENERAL SERVICE TIME OF USE

SUMMER

BILL IMPACTS CURRENT RATES

	Load Factor	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill
		Winter		0.29		$52.00	$12.81	$0.005470	$0.43290	0.114886	0.026168	-$0.002139	
		Summer		0.20						0.114886	0.039886		
Xsm	0.46	27,974	83	5,595	22,379	$52.00	$1,067.14	$153.02	$36.06	$642.76	$892.62	-$59.85	$2,783.75
Small	0.46	28,067	84	5,613	22,454	$52.00	$1,070.69	$153.53	$36.18	$644.90	$895.58	-$60.04	$2,792.84
Medium	0.46	48,453	144	9,691	38,762	$52.00	$1,848.37	$265.04	$62.46	$1,113.31	$1,546.08	-$103.66	$4,783.60
Large	0.56	62,572	186	12,514	50,058	$52.00	$2,386.98	$342.27	$80.67	$1,437.73	$1,996.60	-$133.86	$6,162.39
XLg	0.66	193,470	576	38,694	154,776	$52.00	$7,380.44	$1,058.28	$249.41	$4,445.40	$6,173.40	-$413.90	$18,945.03
AnnAvg	0.58	69,713	208	13,943	55,770	$52.00	$2,659.39	$381.33	$89.87	$1,601.81	$2,224.46	-$149.14	$6,859.72
AvgSum	0.56	73,609	219	14,722	58,887	$52.00	$2,808.00	$402.64	$94.89	$1,691.32	$2,348.76	-$157.47	$7,240.14

BILL IMPACTS PROPOSED RATES

	Load Factor	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
		Winter				$100.00	$13.05	$0.005500	$0.00000	0.089900	0.031600	$0.000000			
		Summer								0.109900	0.033500				
Xsm	0.46	27,974	83	5,595	22,379	$100.00	$1,087.14	$153.86	$0.00	$614.87	$749.70	$0.00	$2,705.57	-$78.18	-2.8%
Small	0.46	28,067	84	5,613	22,454	$100.00	$1,090.75	$154.37	$0.00	$616.91	$752.20	$0.00	$2,714.23	-$78.61	-2.8%
Medium	0.46	48,453	144	9,691	38,762	$100.00	$1,883.00	$266.49	$0.00	$1,065.00	$1,298.54	$0.00	$4,613.03	-$170.57	-3.6%
Large	0.56	62,572	186	12,514	50,058	$100.00	$2,431.70	$344.15	$0.00	$1,375.33	$1,676.93	$0.00	$5,928.11	-$234.28	-3.8%
XLg	0.66	193,470	576	38,694	154,776	$100.00	$7,518.71	$1,064.09	$0.00	$4,252.47	$5,185.00	$0.00	$18,120.27	-$824.76	-4.4%
AnnAvg	0.58	69,713	208	13,943	55,770	$100.00	$2,709.21	$383.42	$0.00	$1,532.29	$1,868.31	$0.00	$6,593.23	-$266.49	-3.9%
AvgSum	0.56	73,609	219	14,722	58,887	$100.00	$2,860.61	$404.85	$0.00	$1,617.92	$1,972.71	$0.00	$6,956.09	-$284.05	-3.9%

												$ Change	% Change	
Current Annual												$81,053.94		
Proposed Annual												$78,930.60	-$2,123.34	-2.6%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

LARGE GENERAL SERVICE TO NEW LARGE GENERAL SERVICE

	BILL IMPACTS CURRENT RATES - LGS									
	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill
				$50.00	$12.81	$0.005470	$0.43290	0.056603	-$0.002139	
Xsm	30%	205	45,000	$50.00	$2,632.19	$246.15	$88.95	$2,547.14	-$96.27	$5,468.16
Small	46%	194	65,000	$50.00	$2,479.60	$355.55	$83.80	$3,679.20	-$139.06	$6,509.09
Medium	66%	844	406,600	$50.00	$10,810.60	$2,224.10	$365.33	$23,014.78	-$869.85	$35,594.96
Large	75%	174	95,000	$50.00	$2,222.74	$519.65	$75.12	$5,377.29	-$203.24	$8,041.56
XLg	95%	1,875	1,300,500	$50.00	$24,022.21	$7,113.74	$811.80	$73,612.20	-$2,782.20	$102,827.75
AnnAvg	65%	992	470,630	$50.00	$12,705.52	$2,574.35	$429.37	$26,639.07	-$1,006.83	$41,391.47

	BILL IMPACTS PROPOSED RATES - LGS											
	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$300.00	$12.96	$0.005400	$0.00000	$0.048400	$0.000000			
Xsm	30%	450	45,000	$300.00	$5,832.00	$243.00	$0.00	$2,178.00	$0.00	$8,553.00	$3,084.84	56.4%
Small	46%	450	65,000	$300.00	$5,832.00	$351.00	$0.00	$3,146.00	$0.00	$9,629.00	$3,119.91	47.9%
Medium	66%	844	406,600	$300.00	$10,937.19	$2,195.64	$0.00	$19,679.44	$0.00	$33,112.27	-$2,482.69	-7.0%
Large	75%	450	95,000	$300.00	$5,832.00	$513.00	$0.00	$4,598.00	$0.00	$11,243.00	$3,201.44	39.8%
XLg	95%	1,875	1,300,500	$300.00	$24,303.50	$7,022.70	$0.00	$62,944.20	$0.00	$94,570.40	-$8,257.34	-8.0%
AnnAvg	65%	992	470,630	$300.00	$12,854.30	$2,541.40	$0.00	$22,778.49	$0.00	$38,474.19	-$2,917.28	-7.0%

LARGE POWER SERVICE <69kV TO NEW LARGE GENERAL SERVICE

BILL IMPACTS CURRENT RATES - LPS <69kV

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill
				$1,200.00	$22.00	$0.000462	$0.43290	$0.04188	-$0.002139	
Xsm	44%	747	240,000	$1,200.00	$16,438.36	$110.88	$323.46	$10,051.20	-$513.44	$27,610.46
Small	46%	893	300,000	$1,200.00	$19,654.56	$138.60	$386.75	$12,564.00	-$641.80	$33,302.11
Medium	66%	844	406,600	$1,200.00	$18,566.21	$187.85	$365.33	$17,028.41	-$869.85	$36,477.95
Large	75%	1,553	850,000	$1,200.00	$34,155.25	$392.70	$672.08	$35,598.00	-$1,818.43	$70,199.60
XLg	75%	2,192	1,200,000	$1,200.00	$48,219.18	$554.40	$948.82	$50,256.00	-$2,567.20	$98,611.20
AnnAvg	65%	992	470,630	$1,200.00	$21,820.57	$217.43	$429.37	$19,709.98	-$1,006.83	$42,370.52

BILL IMPACTS PROPOSED RATES - LPS <69 kV

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$300.00	$12.96	$0.005400	$0.00000	$0.048400	$0.000000			
Xsm	44%	747	240,000	$300.00	$9,683.69	$1,296.00	$0.00	$11,616.00	$0.00	$22,895.69	-$4,714.77	-17.1%
Small	46%	893	300,000	$300.00	$11,578.32	$1,620.00	$0.00	$14,520.00	$0.00	$28,018.32	-$5,283.79	-15.9%
Medium	66%	844	406,600	$300.00	$10,937.19	$2,195.64	$0.00	$19,679.44	$0.00	$33,112.27	-$3,365.68	-9.2%
Large	75%	1,553	850,000	$300.00	$20,120.55	$4,590.00	$0.00	$41,140.00	$0.00	$66,150.55	-$4,049.05	-5.8%
XLg	75%	2,192	1,200,000	$300.00	$28,405.48	$6,480.00	$0.00	$58,080.00	$0.00	$93,265.48	-$5,345.72	-5.4%
AnnAvg	65%	992	470,630	$300.00	$12,854.30	$2,541.40	$0.00	$22,778.49	$0.00	$38,474.19	-$3,896.32	-9.2%

LARGE POWER SERVICE TIME OF USE <69kV TO NEW LARGE GENERAL SERVICE TIME OF USE

WINTER

BILL IMPACTS CURRENT RATES

	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill
	Winter		0.16		$1,200.00	$22.00	$0.000462	$0.43290	$0.093880	$0.022105	-$0.002139	
	Summer		0.16						$0.123580	$0.024716		
Small	433,335	1,281	69,334	364,001	$1,200.00	$28,182.00	$200.20	$554.54	$6,509.04	$8,046.25	-$927.05	$43,764.98
Medium	517,000	1,380	82,720	434,280	$1,200.00	$30,360.00	$238.85	$597.40	$7,765.75	$9,599.76	-$1,106.04	$48,655.72
Large	600,000	1,400	96,000	504,000	$1,200.00	$30,800.00	$277.20	$606.06	$9,012.48	$11,140.92	-$1,283.60	$51,753.06
XLg	775,000	1,570	124,000	651,000	$1,200.00	$34,540.00	$358.05	$679.65	$11,641.12	$14,390.36	-$1,657.98	$61,151.20
Mean	642,400	1,430	102,784	539,616	$1,200.00	$31,460.00	$296.79	$619.05	$9,649.36	$11,928.21	-$1,374.31	$53,779.10
AvgWin	627,900	1,416	100,464	527,436	$1,200.00	$31,152.00	$290.09	$612.99	$9,431.56	$11,658.97	-$1,343.29	$53,002.32

BILL IMPACTS PROPOSED RATES

	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
	Winter				$300.00	$12.96	$0.005400	$0.00000	$0.124510	$0.032910	$0.00000			
	Summer								$0.145510	$0.034510				
Small	433,335	1,281	69,334	364,001	$300.00	$16,601.76	$2,340.01	$0.00	$8,632.73	$11,979.29	$0.00	$39,853.79	-$3,911.19	-8.9%
Medium	517,000	1,380	82,720	434,280	$300.00	$17,884.80	$2,791.80	$0.00	$10,299.47	$14,292.15	$0.00	$45,568.22	-$3,087.50	-6.3%
Large	600,000	1,400	96,000	504,000	$300.00	$18,144.00	$3,240.00	$0.00	$11,952.96	$16,586.64	$0.00	$50,223.60	-$1,529.46	-3.0%
XLg	775,000	1,570	124,000	651,000	$300.00	$20,347.20	$4,185.00	$0.00	$15,439.24	$21,424.41	$0.00	$61,695.85	$544.65	0.9%
Mean	642,400	1,430	102,784	539,616	$300.00	$18,532.80	$3,468.96	$0.00	$12,797.64	$17,758.76	$0.00	$52,858.16	-$920.94	-1.7%
AvgWin	627,900	1,416	100,464	527,436	$300.00	$18,351.36	$3,390.66	$0.00	$12,508.77	$17,357.92	$0.00	$51,908.71	-$1,093.61	-2.1%

LARGE POWER SERVICE TIME OF USE <69kV TO NEW LARGE GENERAL SERVICE TIME OF USE

SUMMER

BILL IMPACTS CURRENT RATES

	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill
	Winter		0.16		$1,200.00	$22.00	$0.000462	$0.43290	$0.093880	$0.022105	-$0.002139	
	Summer		0.16						$0.123580	$0.024716		
Small	433,335	1,281	69,334	364,001	$1,200	$28,182.00	$200.20	$554.54	$8,568.25	$8,996.66	-$927.05	$46,774.60
Medium	517,000	1,380	82,720	434,280	$1,200	$30,360.00	$238.85	$597.40	$10,222.54	$10,733.66	-$1,106.04	$52,246.41
Large	600,000	1,400	96,000	504,000	$1,200	$30,800.00	$277.20	$606.06	$11,863.68	$12,456.86	-$1,283.60	$55,920.20
XLg	775,000	1,570	124,000	651,000	$1,200	$34,540.00	$358.05	$679.65	$15,323.92	$16,090.12	-$1,657.98	$66,533.76
Mean	642,400	1,430	102,784	539,616	$1,200	$31,460.00	$296.79	$619.05	$12,702.05	$13,337.15	-$1,374.31	$58,240.73
AvgSum	656,700	1,444	105,072	551,628	$1,200	$31,768.00	$303.40	$625.11	$12,984.80	$13,634.04	-$1,404.90	$59,110.45

BILL IMPACTS PROPOSED RATES

	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
	Winter				$300.00	$12.96	$0.005400	$0.00000	$0.124510	$0.032910	$0.000000			
	Summer								$0.145510	$0.034510				
Small	433,335	1,281	69,334	364,001	$300.00	$16,601.76	$2,340.01	$0.00	$10,088.73	$12,561.69	$0.00	$41,892.19	-$4,882.41	-10.4%
Medium	517,000	1,380	82,720	434,280	$300.00	$17,884.80	$2,791.80	$0.00	$12,036.59	$14,987.00	$0.00	$48,000.19	-$4,246.22	-8.1%
Large	600,000	1,400	96,000	504,000	$300.00	$18,144.00	$3,240.00	$0.00	$13,968.96	$17,393.04	$0.00	$53,046.00	-$2,874.20	-5.1%
XLg	775,000	1,570	124,000	651,000	$300.00	$20,347.20	$4,185.00	$0.00	$18,043.24	$22,466.01	$0.00	$65,341.45	-$1,192.31	-1.8%
Mean	642,400	1,430	102,784	539,616	$300.00	$18,532.80	$3,468.96	$0.00	$14,956.10	$18,622.15	$0.00	$55,880.01	-$2,360.72	-4.1%
AvgSum	656,700	1,444	105,072	551,628	$300.00	$18,714.24	$3,546.18	$0.00	$15,289.03	$19,036.68	$0.00	$56,886.13	-$2,224.32	-3.8%

												$ Change	% Change
Current Annual											$672,676.62		
Proposed Annual											$652,769.04	-$19,907.58	-2.96%

LARGE POWER SERVICE - TRANSMISSION VOLTAGE

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill
				$1,200.00	$17.00	$0.000462	$0.43290	$0.041880	-$0.002139	
Xsm	0.42	506	155,000	$1,200.00	$8,594.26	$71.61	$218.85	$6,491.40	-$331.60	$16,244.52
Small	0.42	1,267	388,500	$1,200.00	$21,541.10	$179.49	$548.54	$16,270.38	-$831.13	$38,908.37
Small	0.46	1,336	448,600	$1,200.00	$22,710.54	$207.25	$578.32	$18,787.37	-$959.70	$42,523.79
Medium	0.75	2,416	1,322,700	$1,200.00	$41,070.14	$611.09	$1,045.84	$55,394.68	-$2,829.70	$96,492.04
Medium	0.75	2,817	1,542,200	$1,200.00	$47,885.66	$712.50	$1,219.39	$64,587.34	-$3,299.28	$112,305.61
Large	0.89	4,775	3,102,500	$1,200.00	$81,179.78	$1,433.36	$2,067.22	$129,932.70	-$6,637.28	$209,175.77
Large	0.89	5,379	3,494,900	$1,200.00	$91,447.28	$1,614.64	$2,328.68	$146,366.41	-$7,476.76	$235,480.26

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$1,200.00	$12.48	$0.000520	$0.00000	$0.048410	$0.000000			
Xsm	0.42	506	155,000	$1,200.00	$6,309.20	$80.60	$0.00	$7,503.55	$0.00	$15,093.35	-$1,151.17	-7.1%
Small	0.42	1,267	388,500	$1,200.00	$15,813.70	$202.02	$0.00	$18,807.29	$0.00	$36,023.01	-$2,885.36	-7.4%
Small	0.46	1,336	448,600	$1,200.00	$16,672.21	$233.27	$0.00	$21,716.73	$0.00	$39,822.21	-$2,701.57	-6.4%
Medium	0.75	2,416	1,322,700	$1,200.00	$30,150.31	$687.80	$0.00	$64,031.91	$0.00	$96,070.03	-$422.02	-0.4%
Medium	0.75	2,817	1,542,200	$1,200.00	$35,153.71	$801.94	$0.00	$74,657.90	$0.00	$111,813.55	-$492.05	-0.4%
Large	0.89	4,775	3,102,500	$1,200.00	$59,595.51	$1,613.30	$0.00	$150,192.03	$0.00	$212,600.84	$3,425.07	1.6%
Large	0.89	5,379	3,494,900	$1,200.00	$67,133.06	$1,817.35	$0.00	$169,188.11	$0.00	$239,338.52	$3,858.27	1.6%

LARGE POWER SERVICE TIME OF USE >69kV

WINTER

BILL IMPACTS CURRENT RATES

	Total kWh	Demand (kW)	Delivery On-Peak kWh	Delivery Off-Peak kWh	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA /kW	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Total Net Bill
	Winter				$1,200.00	$17.00	$0.000462	$0.43290	$0.093880	$0.022105	-$0.002139	
	Summer		0.11	0.89					$0.123580	$0.024716		
Small	2,790,000	5,083	306,900	2,483,100	$1,200.00	$86,411.00	$1,288.98	$2,200.43	$28,811.77	$54,888.93	-$5,967.81	$168,833.30
Medium	3,150,000	5,083	346,500	2,803,500	$1,200.00	$86,411.00	$1,455.30	$2,200.43	$32,529.42	$61,971.37	-$6,737.85	$179,029.67
Large	2,115,000	5,083	232,650	1,882,350	$1,200.00	$86,411.00	$977.13	$2,200.43	$21,841.18	$41,609.35	-$4,523.99	$149,715.10
Mean	2,717,000	5,083	298,870	2,418,130	$1,200.00	$86,411.00	$1,255.25	$2,200.43	$28,057.92	$53,452.76	-$5,811.66	$166,765.70
AvgWin	2,726,000	5,083	299,860	2,426,140	$1,200.00	$86,411.00	$1,259.41	$2,200.43	$28,150.86	$53,629.82	-$5,830.91	$167,020.61

BILL IMPACTS PROPOSED RATES

	Total kWh	Demand (kW)	Delivery On-Peak kWh	Delivery Off-Peak kWh	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA /kW	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Total Net Bill	$ Change	% Change
	Winter				$1,200.00	$12.48	$0.000520	$0.00000	$0.092110	$0.030910				
	Summer								$0.122510	$0.032110	$0.000000			
Small	2,790,000	5,083	306,900	2,483,100	$1,200.00	$63,435.84	$1,450.80	$0.00	$28,268.56	$76,752.62	$0.00	$171,107.82	$2,274.52	1.35%
Medium	3,150,000	5,083	346,500	2,803,500	$1,200.00	$63,435.84	$1,638.00	$0.00	$31,916.12	$86,656.19	$0.00	$184,846.15	$5,816.48	3.25%
Large	2,115,000	5,083	232,650	1,882,350	$1,200.00	$63,435.84	$1,099.80	$0.00	$21,429.39	$58,183.44	$0.00	$145,348.47	-$4,366.63	-2.92%
Mean	2,717,000	5,083	298,870	2,418,130	$1,200.00	$63,435.84	$1,412.84	$0.00	$27,528.92	$74,744.40	$0.00	$168,322.00	$1,556.30	0.93%
AvgWin	2,726,000	5,083	299,860	2,426,140	$1,200.00	$63,435.84	$1,417.52	$0.00	$27,620.10	$74,991.99	$0.00	$168,665.45	$1,644.84	0.98%

LARGE POWER SERVICE TIME OF USE >69kV

SUMMER

BILL IMPACTS CURRENT RATES

	Total kWh	Demand (kW)	Delivery On-Peak kWh	Delivery Off-Peak kWh	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA /kW	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Total Net Bill
	Winter				$1,200.00	$17.00	$0.000462	$0.43290	$0.093880	$0.022105	-$0.002139	
	Summer		0.11	0.89					$0.123580	$0.024716		
Small	2,790,000	5,083	306,900	2,483,100	$1,200.00	$86,411.00	$1,288.98	$2,200.43	$37,926.70	$61,372.30	-$5,967.81	$184,431.60
Medium	3,150,000	5,083	346,500	2,803,500	$1,200.00	$86,411.00	$1,455.30	$2,200.43	$42,820.47	$69,291.31	-$6,737.85	$196,640.66
Large	2,115,000	5,083	232,650	1,882,350	$1,200.00	$86,411.00	$977.13	$2,200.43	$28,750.89	$46,524.16	-$4,523.99	$161,539.62
Mean	2,717,000	5,083	298,870	2,418,130	$1,200.00	$86,411.00	$1,255.25	$2,200.43	$36,934.35	$59,766.50	-$5,811.66	$181,955.87
AvgSum	2,790,000	5,083	311,600	2,478,400	$1,200.00	$86,411.00	$1,288.98	$2,200.43	$38,507.53	$61,256.13	-$5,967.81	$184,896.26

BILL IMPACTS PROPOSED RATES

	Total kWh	Demand (kW)	Delivery On-Peak kWh	Delivery Off-Peak kWh	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA /kW	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Total Net Bill	$ Change	% Change
	Winter				$1,200.00	$12.48	$0.000520	$0.00000	$0.092110	$0.030910				
	Summer								$0.122510	$0.032110	$0.000000			
Small	2,790,000	5,083	306,900	2,483,100	$1,200	$63,436	$1,451	$0.00	$37,598.32	$79,732.34	$0.00	$183,417	-$1,014.30	-0.55%
Medium	3,150,000	5,083	346,500	2,803,500	$1,200	$63,436	$1,638	$0.00	$42,449.72	$90,020.39	$0.00	$198,744	$2,103.29	1.07%
Large	2,115,000	5,083	232,650	1,882,350	$1,200	$63,436	$1,100	$0.00	$28,501.95	$60,442.26	$0.00	$154,680	-$6,859.77	-4.25%
Mean	2,717,000	5,083	298,870	2,418,130	$1,200	$63,436	$1,413	$0.00	$36,614.56	$77,646.15	$0.00	$180,309	-$1,646.48	-0.90%
AvgSum	2,790,000	5,083	311,600	2,478,400	$1,200	$63,436	$1,451	$0.00	$38,174.12	$79,581.42	$0.00	$183,842	-$1,054.08	-0.57%

	Total Net Bill	$ Change	% Change
Current Annual	$2,111,501		
Proposed Annual	$2,115,046	$3,545	0.17%

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending December 31, 2014

LIGHTING SERVICE

Description	Old Rate	New Rate
New 30' Wood Pole (Class 6) - Overhead	$4.34	$4.68
New 30' Metal or Fiberglass - Overhead	$8.66	$9.35
Existing Wood Pole - Underground	$2.18	$2.35
New 30' Wood Pole (Class 6) - Underground	$6.52	$7.04
New 30' Metal or Fiberglass - Underground	$10.81	$11.67
Wattage, per Watt	$0.051681	$0.060516
Base Power Supply	$0.010113	$0.013110
PPFAC	-$0.002139	$0.000000

		Proration
New Rate Days	**28**	100%
Old Rate Days	0	0%

Total Days	28
Total kWh billed	150

Customer Bill	Current Rates	Proposed Rates	$Change	%Change
100 Watt	$5.17	$6.05	$0.88	17.02%
150 Watt	$7.75	$9.08	$1.33	17.16%
200 Watt	$10.34	$12.10	$1.76	17.02%
250 Watt	$12.92	$15.13	$2.21	17.11%
400 Watt	$20.67	$24.21	$3.54	17.13%
Existing Wood Pole OH	$4.34	$4.68	$0.34	7.83%
New 30' Wood Pole OH	$8.66	$9.35	$0.69	7.97%
New 30' Metal or FG OH	$2.18	$2.35	$0.17	7.80%
Existing Wood Pole UG	$6.52	$7.04	$0.52	7.98%
New 30' Wood Pole UG	$10.81	$11.67	$0.86	7.96%
New 30' Metal or FG UG	$0.05	$0.06	$0.01	17.10%
Base Power Supply	$1.52	$1.97	$0.45	29.61%
PPFAC	($0.32)	$0.00	$0.32	-100.00%
Typical	$13.29	$15.73	$2.44	18.36%

Detail of Services Billed	Wattage	Units Billed
100 Watt	100	1
150 Watt	150	1
200 Watt	200	1
250 Watt	250	1
400 Watt	400	1
Existing Wood Pole OH		5
New 30' Wood Pole OH		0
New 30' Metal or FG OH		0
Existing Wood Pole UG		0
New 30' Wood Pole UG		0
New 30' Metal or FG UG		0

UNS Electric, Inc.
Bill Count
Test Period Ending December 31, 2014
Unadjusted Billing Activity

RESIDENTIAL SERVICE (RES-01)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	23,222	0	23,222	2.55%	0	0.00%
1	10	9,428	48,913	32,650	3.59%	48,913	0.01%
11	20	6,606	103,699	39,256	4.31%	152,612	0.02%
21	30	5,845	150,511	45,101	4.96%	303,124	0.04%
31	40	5,413	193,913	50,514	5.55%	497,037	0.07%
41	50	5,219	239,906	55,733	6.12%	736,943	0.10%
51	60	5,537	309,869	61,270	6.73%	1,046,812	0.14%
61	70	5,614	370,673	66,884	7.35%	1,417,485	0.19%
71	80	5,803	440,899	72,687	7.99%	1,858,384	0.25%
81	90	5,843	502,161	78,530	8.63%	2,360,545	0.31%
91	100	5,805	557,461	84,335	9.27%	2,918,007	0.39%
101	200	58,092	8,779,849	142,427	15.65%	11,697,856	1.55%
201	300	62,702	15,810,239	205,129	22.54%	27,508,094	3.64%
301	400	69,033	24,262,616	274,162	30.12%	51,770,710	6.86%
401	500	71,057	32,044,933	345,219	37.93%	83,815,643	11.10%
501	600	68,091	37,490,833	413,310	45.41%	121,306,477	16.07%
601	700	63,292	41,157,673	476,602	52.36%	162,464,149	21.52%
701	800	56,869	42,656,729	533,471	58.61%	205,120,878	27.17%
801	900	50,051	42,539,349	583,522	64.11%	247,660,228	32.80%
901	1,000	44,575	42,351,489	628,097	69.01%	290,011,716	38.41%
1,001	1,500	150,789	184,384,331	778,886	85.58%	474,396,047	62.83%
1,501	2,000	72,099	124,007,014	850,985	93.50%	598,403,062	79.26%
2,001	2,500	32,995	73,185,522	883,980	97.12%	671,588,584	88.95%
2,501	3,000	14,244	38,716,028	898,224	98.69%	710,304,612	94.08%
3,001	3,500	6,293	20,270,166	904,517	99.38%	730,574,778	96.76%
3,501	4,000	2,821	10,491,682	907,338	99.69%	741,066,460	98.15%
4,001	4,500	1,277	5,390,695	908,615	99.83%	746,457,155	98.87%
4,501	5,000	614	2,898,696	909,229	99.90%	749,355,851	99.25%
5,001	6,000	579	3,136,820	909,808	99.96%	752,492,671	99.67%
6,001	7,000	189	1,217,447	909,997	99.98%	753,710,118	99.83%
7,001	8,000	101	749,173	910,098	99.99%	754,459,291	99.93%
8,001	9,000	37	313,361	910,135	100.00%	754,772,652	99.97%
9,001	10,000	15	141,205	910,150	100.00%	754,913,857	99.99%
10,001	15,000	8	91,760	910,158	100.00%	755,005,617	100.00%

Average Customers	75,847
Average kWh per Bill	830
Median kWh	666

RESIDENTIAL SERVICE CARES (CARES & CARES-MF)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	192	0	192	0.26%	0	0.00%
1	10	144	835	336	0.45%	835	0.00%
11	20	72	1,152	408	0.55%	1,987	0.00%
21	30	120	3,029	528	0.71%	5,016	0.01%
31	40	111	4,013	639	0.86%	9,029	0.02%
41	50	118	5,446	757	1.02%	14,475	0.03%
51	60	138	7,686	895	1.20%	22,161	0.04%
61	70	140	9,253	1,035	1.39%	31,414	0.05%
71	80	159	12,137	1,194	1.61%	43,551	0.08%
81	90	214	18,469	1,408	1.90%	62,020	0.11%
91	100	252	24,067	1,660	2.23%	86,087	0.15%
101	200	4,334	682,476	5,994	8.07%	768,563	1.35%
201	300	7,005	1,773,288	12,999	17.50%	2,541,851	4.45%
301	400	8,113	2,851,663	21,112	28.42%	5,393,514	9.44%
401	500	7,680	3,458,542	28,792	38.76%	8,852,057	15.49%
501	600	6,998	3,847,208	35,790	48.18%	12,699,265	22.23%
601	700	6,100	3,965,146	41,890	56.39%	16,664,411	29.16%
701	800	5,256	3,940,083	47,146	63.46%	20,604,494	36.06%
801	900	4,521	3,841,013	51,667	69.55%	24,445,507	42.78%
901	1,000	3,677	3,492,371	55,344	74.50%	27,937,879	48.89%
1,001	1,500	11,410	13,870,637	66,754	89.85%	41,808,515	73.17%
1,501	2,000	4,613	7,920,324	71,367	96.06%	49,728,839	87.03%
2,001	2,500	1,788	3,961,203	73,155	98.47%	53,690,042	93.96%
2,501	3,000	697	1,888,834	73,852	99.41%	55,578,876	97.27%
3,001	3,500	262	840,394	74,114	99.76%	56,419,270	98.74%
3,501	4,000	105	387,949	74,219	99.90%	56,807,219	99.42%
4,001	4,500	37	155,176	74,256	99.95%	56,962,395	99.69%
4,501	5,000	20	94,056	74,276	99.98%	57,056,451	99.86%
5,001	6,000	12	63,814	74,288	100.00%	57,120,265	99.97%
6,001	7,000	3	18,472	74,291	100.00%	57,138,737	100.00%

Average Customers	6,112
Average kWh per Bill	769
Median kWh	622

RESIDENTIAL SERVICE TOU (RES-01 TOU)

SUMMER (MAY - OCTOBER)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	6	0	6	0.42%	0	0.00%
1	100	28	1,376	34	2.38%	1,376	0.08%
101	200	60	9,212	94	6.59%	10,588	0.62%
201	300	53	13,385	147	10.30%	23,973	1.41%
301	400	74	25,520	221	15.49%	49,493	2.90%
401	500	65	29,623	286	20.04%	79,116	4.64%
501	600	75	40,932	361	25.30%	120,048	7.04%
601	700	79	51,293	440	30.83%	171,341	10.05%
701	800	91	68,438	531	37.21%	239,779	14.06%
801	900	82	69,676	613	42.96%	309,455	18.15%
901	1,000	89	84,386	702	49.19%	393,841	23.10%
1,001	2,000	510	735,420	1,212	84.93%	1,129,261	66.24%
2,001	3,000	172	411,881	1,384	96.99%	1,541,142	90.40%
3,001	4,000	36	124,826	1,420	99.51%	1,665,968	97.72%
4,001	5,000	6	26,247	1,426	99.93%	1,692,215	99.26%
5,001	10,000	0	0	1,426	99.93%	1,692,215	99.26%
10,001	15,000	1	12,671	1,427	100.00%	1,704,886	100.00%

Average Customers	238
Average kWh per Bill	1,195
Median kWh	1,008

WINTER (NOVEMBER - APRIL)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	11	0	11	0.86%	0	0.00%
1	100	31	1,966	42	3.28%	1,966	0.19%
101	200	77	12,108	119	9.28%	14,074	1.37%
201	300	103	26,332	222	17.32%	40,406	3.94%
301	400	92	32,254	314	24.49%	72,660	7.08%
401	500	112	50,789	426	33.23%	123,449	12.03%
501	600	98	53,810	524	40.87%	177,259	17.28%
601	700	132	85,903	656	51.17%	263,162	25.65%
701	800	94	70,567	750	58.50%	333,729	32.53%
801	900	79	67,204	829	64.66%	400,933	39.07%
901	1,000	69	65,236	898	70.05%	466,169	45.43%
1,001	2,000	340	449,947	1,238	96.57%	916,116	89.28%
2,001	3,000	40	92,368	1,278	99.69%	1,008,484	98.29%
3,001	4,000	2	7,224	1,280	99.84%	1,015,708	98.99%
4,001	5,000	1	4,329	1,281	99.92%	1,020,037	99.41%
5,001	10,000	1	6,029	1,282	100.00%	1,026,066	100.00%
10,001	15,000	0	0	1,282	100.00%	1,026,066	100.00%

Average Customers	220
Average kWh per Bill	800
Median kWh	676

RESIDENTIAL SERVICE TOU SUPER PEAK (RES-01 TOU SP)

During the test year there was only 1 bill for Residential Service Time-of-Use Super Peak.
As such, we are not showing a Bill Count exhibit for this class.

RESIDENTIAL SERVICE BRIGHT ARIZONA COMMUNITY SOLAR

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	0	0	0	0.00%	0	0.00%
1	100	3	160	3	0.31%	160	0.02%
101	200	93	14,315	96	10.01%	14,475	1.71%
201	300	103	28,951	199	20.75%	43,426	5.12%
301	400	38	13,473	237	24.71%	56,899	6.71%
401	500	61	27,378	298	31.07%	84,277	9.94%
501	600	78	44,951	376	39.21%	129,228	15.24%
601	700	46	30,085	422	44.00%	159,313	18.79%
701	800	112	84,317	534	55.68%	243,630	28.73%
801	900	82	71,579	616	64.23%	315,209	37.17%
901	1,000	27	25,647	643	67.05%	340,856	40.19%
1,001	1,500	179	212,011	822	85.71%	552,867	65.19%
1,501	2,000	78	133,770	900	93.85%	686,637	80.97%
2,001	2,500	33	73,697	933	97.29%	760,334	89.66%
2,501	3,000	13	34,693	946	98.64%	795,027	93.75%
3,001	4,000	8	26,992	954	99.48%	822,019	96.93%
4,001	5,000	1	4,076	955	99.58%	826,095	97.41%
5,001	6,000	4	21,968	959	100.00%	848,063	100.00%

Average Customers	79
Average kWh per Bill	884
Median kWh	750

SMALL GENERAL SERVICE (SGS-10)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	4,885	0	4,885	4.65%	0	0.00%
1	100	14,297	584,716	19,182	18.27%	584,716	0.49%
101	200	8,608	1,288,065	27,790	26.47%	1,872,781	1.58%
201	300	7,929	1,977,319	35,719	34.02%	3,850,101	3.24%
301	400	7,077	2,474,095	42,796	40.76%	6,324,196	5.33%
401	500	6,153	2,768,466	48,949	46.62%	9,092,662	7.66%
501	600	5,236	2,876,783	54,185	51.61%	11,969,445	10.08%
601	700	4,269	2,772,776	58,454	55.67%	14,742,221	12.41%
701	800	3,710	2,782,073	62,164	59.20%	17,524,294	14.76%
801	900	3,293	2,800,963	65,457	62.34%	20,325,257	17.12%
901	1,000	3,005	2,856,921	68,462	65.20%	23,182,178	19.52%
1,001	1,500	11,116	13,700,070	79,578	75.79%	36,882,248	31.06%
1,501	2,000	7,086	12,279,255	86,664	82.54%	49,161,504	41.40%
2,001	2,500	4,697	10,506,975	91,361	87.01%	59,668,479	50.25%
2,501	3,000	3,483	9,536,631	94,844	90.33%	69,205,110	58.28%
3,001	3,500	2,605	8,437,011	97,449	92.81%	77,642,120	65.38%
3,501	4,000	2,098	7,846,503	99,547	94.81%	85,488,623	71.99%
4,001	4,500	1,392	5,898,017	100,939	96.13%	91,386,640	76.95%
4,501	5,000	1,049	4,966,235	101,988	97.13%	96,352,875	81.14%
5,001	5,500	706	3,697,983	102,694	97.81%	100,050,858	84.25%
5,501	6,000	561	3,219,873	103,255	98.34%	103,270,731	86.96%
6,001	6,500	393	2,454,022	103,648	98.71%	105,724,753	89.03%
6,501	7,000	306	2,061,787	103,954	99.01%	107,786,540	90.76%
7,001	7,500	212	1,535,016	104,166	99.21%	109,321,555	92.06%
7,501	8,000	150	1,160,538	104,316	99.35%	110,482,093	93.03%
8,001	9,000	221	1,875,110	104,537	99.56%	112,357,203	94.61%
9,001	10,000	147	1,392,940	104,684	99.70%	113,750,143	95.79%
10,001	25,000	285	3,949,419	104,969	99.97%	117,699,562	99.11%
25,001	50,000	27	874,599	104,996	100.00%	118,574,161	99.85%
50,001	100,000	2	180,240	104,998	100.00%	118,754,401	100.00%

Average Customers	8,704
Average kWh per Bill	1,131
Median kWh	566

SMALL GENERAL SERVICE TOU (SGS-10 TOU)

SUMMER (MAY - OCTOBER)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	0	0	0	0.00%	0	0.00%
1	400	1	352	1	2.27%	352	0.35%
401	800	4	2,894	5	11.36%	3,246	3.27%
801	1,200	4	4,031	9	20.45%	7,277	7.33%
1,201	1,600	3	3,811	12	27.27%	11,088	11.17%
1,601	2,000	5	8,568	17	38.64%	19,656	19.80%
2,001	2,400	4	8,625	21	47.73%	28,281	28.49%
2,401	2,800	8	21,004	29	65.91%	49,285	49.64%
2,801	3,200	8	24,784	37	84.09%	74,069	74.61%
3,201	3,600	3	10,238	40	90.91%	84,307	84.92%
3,601	4,000	3	10,937	43	97.73%	95,244	95.94%
4,001	4,400	1	4,035	44	100.00%	99,279	100.00%

Average Customers	8
Average kWh per Bill	2,256
Median kWh	2,434

WINTER (NOVEMBER - APRIL)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	0	0	0	0.00%	0	0.00%
1	400	5	791	5	10.87%	791	1.11%
401	800	9	5,548	14	30.43%	6,339	8.88%
801	1,200	4	3,713	18	39.13%	10,052	14.09%
1,201	1,600	4	5,640	22	47.83%	15,692	21.99%
1,601	2,000	7	12,663	29	63.04%	28,355	39.74%
2,001	2,400	7	15,010	36	78.26%	43,365	60.78%
2,401	2,800	7	17,661	43	93.48%	61,026	85.53%
2,801	3,200	1	3,194	44	95.65%	64,220	90.01%
3,201	3,600	1	3,480	45	97.83%	67,700	94.89%
3,601	4,000	1	3,649	46	100.00%	71,349	100.00%
4,001	4,400	0	0	46	100.00%	71,349	100.00%

Average Customers	8
Average kWh per Bill	1,551
Median kWh	1,776

INTERRUPTIBLE POWER SERVICE (IPS)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	7	0	7	1.79%	0	0.00%
1	500	32	4,732	39	10.00%	4,732	0.01%
501	1,000	8	6,080	47	12.05%	10,812	0.03%
1,001	1,500	7	8,600	54	13.85%	19,412	0.05%
1,501	2,000	2	3,560	56	14.36%	22,972	0.06%
2,001	2,500	6	13,280	62	15.90%	36,252	0.10%
2,501	3,000	0	0	62	15.90%	36,252	0.10%
3,001	3,500	4	12,888	66	16.92%	49,140	0.13%
3,501	4,000	4	14,855	70	17.95%	63,995	0.17%
4,001	4,500	3	12,360	73	18.72%	76,355	0.20%
4,501	5,000	1	4,720	74	18.97%	81,075	0.21%
5,001	10,000	14	103,579	88	22.56%	184,654	0.48%
10,001	15,000	23	306,280	111	28.46%	490,934	1.29%
15,001	20,000	40	701,395	151	38.72%	1,192,329	3.13%
20,001	25,000	32	714,853	183	46.92%	1,907,182	5.00%
25,001	40,000	41	1,306,450	224	57.44%	3,213,632	8.43%
40,001	55,000	35	1,640,040	259	66.41%	4,853,672	12.74%
55,001	70,000	16	973,200	275	70.51%	5,826,872	15.29%
70,001	85,000	17	1,335,280	292	74.87%	7,162,152	18.80%
85,001	100,000	11	1,021,480	303	77.69%	8,183,632	21.48%
100,001	125,000	11	1,227,680	314	80.51%	9,411,312	24.70%
125,001	150,000	9	1,226,680	323	82.82%	10,637,992	27.92%
150,001	175,000	5	804,000	328	84.10%	11,441,992	30.03%
175,001	200,000	7	1,328,240	335	85.90%	12,770,232	33.51%
200,001	225,000	8	1,669,400	343	87.95%	14,439,632	37.89%
225,001	250,000	5	1,179,600	348	89.23%	15,619,232	40.99%
250,001	300,000	10	2,686,080	358	91.79%	18,305,312	48.04%
300,001	350,000	7	2,290,400	365	93.59%	20,595,712	54.05%
350,001	400,000	1	380,400	366	93.85%	20,976,112	55.05%
400,001	500,000	2	901,119	368	94.36%	21,877,231	57.41%
500,001	750,000	12	7,561,720	380	97.44%	29,438,951	77.25%
750,001	1,000,000	9	7,615,196	389	99.74%	37,054,147	97.24%
1,000,001	1,250,000	1	1,052,155	390	100.00%	38,106,302	100.00%

Average Customers	32
Average kWh per Bill	97,708
Median kWh	28,260

LARGE GENERAL SERVICE (LGS)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	86	0	86	0.51%	0	0.00%
1	100	95	5,472	181	1.08%	5,472	0.00%
101	200	48	7,186	229	1.37%	12,658	0.00%
201	300	29	7,348	258	1.54%	20,006	0.00%
301	400	12	4,314	270	1.61%	24,320	0.01%
401	500	21	9,745	291	1.74%	34,065	0.01%
501	600	12	6,553	303	1.81%	40,618	0.01%
601	700	14	9,236	317	1.89%	49,854	0.01%
701	800	30	22,929	347	2.07%	72,783	0.02%
801	900	19	16,286	366	2.19%	89,069	0.02%
901	1,000	18	17,146	384	2.29%	106,215	0.02%
1,001	2,000	201	305,772	585	3.49%	411,987	0.09%
2,001	3,000	293	757,622	878	5.24%	1,169,609	0.26%
3,001	4,000	628	2,255,378	1,506	8.99%	3,424,987	0.76%
4,001	5,000	792	3,577,785	2,298	13.72%	7,002,772	1.56%
5,001	6,000	1,021	5,642,104	3,319	19.82%	12,644,876	2.82%
6,001	7,000	990	6,437,397	4,309	25.73%	19,082,273	4.25%
7,001	8,000	953	7,155,147	5,262	31.43%	26,237,419	5.85%
8,001	9,000	847	7,204,055	6,109	36.48%	33,441,474	7.45%
9,001	10,000	738	7,013,052	6,847	40.89%	40,454,526	9.02%
10,001	11,000	586	6,151,008	7,433	44.39%	46,605,534	10.39%
11,001	12,000	552	6,355,315	7,985	47.69%	52,960,849	11.80%
12,001	13,000	517	6,472,493	8,502	50.78%	59,433,342	13.25%
13,001	14,000	435	5,877,068	8,937	53.37%	65,310,409	14.56%
14,001	15,000	411	5,956,080	9,348	55.83%	71,266,489	15.88%
15,001	16,000	380	5,897,100	9,728	58.10%	77,163,589	17.20%
16,001	17,000	350	5,777,571	10,078	60.19%	82,941,160	18.49%
17,001	18,000	282	4,936,221	10,360	61.87%	87,877,381	19.59%
18,001	19,000	304	5,614,154	10,664	63.69%	93,491,535	20.84%
19,001	20,000	280	5,471,247	10,944	65.36%	98,962,782	22.06%
20,001	30,000	2,028	49,835,080	12,972	77.47%	148,797,862	33.16%
30,001	40,000	1,176	40,450,403	14,148	84.50%	189,248,265	42.18%
40,001	50,000	632	28,094,658	14,780	88.27%	217,342,923	48.44%
50,001	75,000	763	46,502,598	15,543	92.83%	263,845,521	58.81%
75,001	100,000	357	30,626,570	15,900	94.96%	294,472,091	65.63%
100,001	125,000	205	22,906,658	16,105	96.18%	317,378,749	70.74%
125,001	150,000	174	23,905,224	16,279	97.22%	341,283,973	76.06%
150,001	175,000	107	17,424,892	16,386	97.86%	358,708,865	79.95%
175,001	200,000	90	16,812,238	16,476	98.40%	375,521,103	83.69%
200,001	225,000	87	18,385,020	16,563	98.92%	393,906,123	87.79%
225,001	250,000	45	10,645,601	16,608	99.19%	404,551,724	90.17%
250,001	300,000	56	15,216,250	16,664	99.52%	419,767,974	93.56%
300,001	350,000	42	13,652,150	16,706	99.77%	433,420,124	96.60%
350,001	400,000	24	8,900,900	16,730	99.92%	442,321,024	98.58%
400,001	450,000	8	3,355,500	16,738	99.96%	445,676,524	99.33%
450,001	500,000	5	2,396,450	16,743	99.99%	448,072,974	99.87%
500,001	600,000	0	0	16,743	99.99%	448,072,974	99.87%
600,001	700,000	1	605,600	16,744	100.00%	448,678,574	100.00%
			Average Customers	1,361			
			Average kWh per Bill	26,796			
			Median kWh	12,560			

LARGE GENERAL SERVICE TOU (LGS TOU)

SUMMER (MAY - OCTOBER)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	1	0	1	3.57%	0	0.00%
1	25,000	0	0	1	3.57%	0	0.00%
25,001	50,000	11	399,183	12	42.86%	399,183	19.37%
50,001	100,000	9	560,383	21	75.00%	959,566	46.56%
100,001	150,000	5	656,839	26	92.86%	1,616,405	78.43%
150,001	300,000	2	444,634	28	100.00%	2,061,039	100.00%

Average Customers	5
Average kWh per Bill	73,609
Median kWh	54,932

WINTER (NOVEMBER - APRIL)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	1	0	1	3.70%	0	0.00%
1	25,000	1	2,019	2	7.41%	2,019	0.11%
25,001	50,000	13	458,116	15	55.56%	460,135	25.95%
50,001	100,000	4	223,868	19	70.37%	684,003	38.58%
100,001	150,000	6	684,893	25	92.59%	1,368,896	77.20%
150,001	300,000	2	404,276	27	100.00%	1,773,172	100.00%

Average Customers	4
Average kWh per Bill	65,673
Median kWh	47,687

LARGE GENERAL SERVICE BRIGHT ARIZONA COMMUNITY SOLAR

During the test year there were only 3 bills in the LGS class under the Bright Arizona Community Solar Program. As such, we are not showing a Bill Count exhibit for this group of customers.

LARGE POWER SERVICE (LPS)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	3	0	3	1.53%	0	0.00%
1	250,000	4	490,240	7	3.57%	490,240	0.24%
250,001	500,000	56	21,802,225	63	32.14%	22,292,465	10.86%
500,001	750,000	46	27,718,120	109	55.61%	50,010,585	24.37%
750,001	1,000,000	29	25,155,581	138	70.41%	75,166,166	36.63%
1,000,001	3,000,000	38	53,834,758	176	89.80%	129,000,924	62.86%
3,000,001	6,000,000	20	76,226,777	196	100.00%	205,227,701	100.00%

Average Customers	16
Average kWh per Bill	1,047,080
Median kWh	633,800

REDACTED

LARGE POWER SERVICE TOU (LPS TOU)

SUMMER (MAY - OCTOBER)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	xx	xx	xx	xx	xx	xx
1	1,000,000	xx	xx	xx	xx	xx	xx
1,000,001	2,000,000	xx	xx	xx	xx	xx	xx
2,000,001	3,000,000	xx	xx	xx	xx	xx	xx
3,000,001	4,000,000	xx	xx	xx	xx	xx	xx

Average Customers	xx
Average kWh per Bill	xx
Median kWh	xx

WINTER (NOVEMBER - APRIL)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	xx	xx	xx	xx	xx	xx
1	1,000,000	xx	xx	xx	xx	xx	xx
1,000,001	2,000,000	xx	xx	xx	xx	xx	xx
2,000,001	3,000,000	xx	xx	xx	xx	xx	xx
3,000,001	4,000,000	xx	xx	xx	xx	xx	xx

Average Customers	xx
Average kWh per Bill	xx
Median kWh	xx

Customer specific information that could be considered confidential has been redacted and will be provided pursuant to the terms of the Protective Agreement in this docket.

LIGHTING SERVICE (LTG)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	0	0	0	0.00%	0	0.00%
1	10	39	309	39	0.14%	309	0.01%
11	20	145	1,967	184	0.64%	2,276	0.08%
21	30	99	2,579	283	0.99%	4,855	0.17%
31	40	10,574	385,813	10,857	38.02%	390,668	13.85%
41	50	7,344	327,217	18,201	63.74%	717,885	25.46%
51	60	1,989	104,249	20,190	70.71%	822,134	29.15%
61	70	897	59,226	21,087	73.85%	881,360	31.25%
71	80	1,189	90,318	22,276	78.01%	971,678	34.46%
81	90	1,439	122,675	23,715	83.05%	1,094,353	38.81%
91	100	739	70,772	24,454	85.64%	1,165,125	41.32%
101	200	2,503	337,882	26,957	94.40%	1,503,007	53.30%
201	300	567	134,988	27,524	96.39%	1,637,995	58.08%
301	400	312	108,410	27,836	97.48%	1,746,405	61.93%
401	500	178	78,912	28,014	98.11%	1,825,317	64.73%
501	600	102	55,690	28,116	98.46%	1,881,007	66.70%
601	700	64	41,598	28,180	98.69%	1,922,605	68.18%
701	800	45	33,816	28,225	98.84%	1,956,421	69.38%
801	900	43	36,436	28,268	98.99%	1,992,857	70.67%
901	1,000	39	36,862	28,307	99.13%	2,029,719	71.98%
1,001	2,000	146	203,772	28,453	99.64%	2,233,491	79.20%
2,001	3,000	50	120,175	28,503	99.82%	2,353,666	83.46%
3,001	4,000	17	58,292	28,520	99.88%	2,411,958	85.53%
4,001	5,000	10	43,962	28,530	99.91%	2,455,920	87.09%
5,001	10,000	1	5,582	28,531	99.92%	2,461,502	87.29%
10,001	15,000	14	187,503	28,545	99.96%	2,649,005	93.94%
15,001	20,000	10	171,008	28,555	100.00%	2,820,013	100.00%

Average Customers	2,388
Average kWh per Bill	99
Median kWh	44

Overhead Services	Number of Items	Wattage
New 30' Wood Pole (Class 6)	8,574	
New 30' Metal or Fiberglass	5,829	
100 watt Bulb	25,609	2,560,900
150 watt Bulb	9,080	1,362,000
200 watt Bulb	6,424	1,284,800
250 watt Bulb	2,837	709,250
400 watt Bulb	1,274	509,600

Underground Services	Number of Items	Wattage
Existing Wood Pole	372	
New 30' Wood Pole (Class 6)	176	
New 30' Metal or Fiberglass	2,699	
100 watt Bulb	5,670	567,000
150 watt Bulb	230	34,500
200 watt Bulb	336	67,200
250 watt Bulb	1,152	288,000
400 watt Bulb	268	107,200

RESIDENTIAL SERVICE (RES-01)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	23,280	0	23,280	2.55%	0	0.00%
1	10	9,451	47,406	32,731	3.59%	47,406	0.01%
11	20	6,622	100,503	39,354	4.31%	147,909	0.02%
21	30	5,860	145,872	45,213	4.96%	293,781	0.04%
31	40	5,426	187,937	50,640	5.55%	481,718	0.06%
41	50	5,232	232,512	55,872	6.12%	714,230	0.09%
51	60	5,551	300,319	61,422	6.73%	1,014,549	0.13%
61	70	5,628	359,249	67,050	7.35%	1,373,798	0.18%
71	80	5,817	427,310	72,868	7.99%	1,801,108	0.24%
81	90	5,858	486,684	78,725	8.63%	2,287,792	0.30%
91	100	5,819	540,280	84,545	9.27%	2,828,072	0.37%
101	200	58,236	8,509,250	142,781	15.65%	11,337,322	1.49%
201	300	62,858	15,322,959	205,639	22.54%	26,660,281	3.50%
301	400	69,205	23,514,830	274,843	30.12%	50,175,111	6.59%
401	500	71,234	32,077,298	346,077	37.93%	82,252,408	10.81%
501	600	68,260	37,450,167	414,337	45.41%	119,702,576	15.73%
601	700	63,449	41,053,206	477,786	52.36%	160,755,782	21.12%
701	800	57,010	42,502,889	534,797	58.61%	203,258,670	26.70%
801	900	50,175	42,351,154	584,972	64.11%	245,609,824	32.27%
901	1,000	44,686	42,136,689	629,658	69.01%	287,746,513	37.80%
1,001	1,500	151,164	186,186,764	780,822	85.58%	473,933,277	62.26%
1,501	2,000	72,278	126,392,103	853,100	93.50%	600,325,380	78.86%
2,001	2,500	33,077	74,975,475	886,177	97.12%	675,300,855	88.71%
2,501	3,000	14,279	39,791,401	900,456	98.69%	715,092,256	93.94%
3,001	3,500	6,309	20,879,785	906,765	99.38%	735,972,041	96.68%
3,501	4,000	2,828	10,824,669	909,593	99.69%	746,796,710	98.11%
4,001	4,500	1,280	5,568,686	910,873	99.83%	752,365,396	98.84%
4,501	5,000	616	2,997,313	911,489	99.90%	755,362,709	99.23%
5,001	6,000	580	3,246,957	912,069	99.96%	758,609,666	99.66%
6,001	7,000	189	1,261,622	912,259	99.98%	759,871,288	99.82%
7,001	8,000	101	776,969	912,360	99.99%	760,648,257	99.93%
8,001	9,000	37	325,197	912,397	100.00%	760,973,455	99.97%
9,001	10,000	15	146,606	912,412	100.00%	761,120,060	99.99%
10,001	15,000	8	95,339	912,420	100.00%	761,215,400	100.00%

Average Customers	76,035
Average kWh per Bill	834
Median kWh	601 - 700

RESIDENTIAL SERVICE CARES (CARES & CARES-MF)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	193	0	193	0.26%	0	0.00%
1	10	145	855	338	0.45%	855	0.00%
11	20	73	1,180	411	0.55%	2,036	0.00%
21	30	121	3,103	532	0.71%	5,139	0.01%
31	40	112	4,111	644	0.86%	9,250	0.02%
41	50	119	5,580	763	1.02%	14,830	0.03%
51	60	139	7,875	902	1.20%	22,705	0.04%
61	70	141	9,480	1,043	1.39%	32,185	0.05%
71	80	160	12,435	1,203	1.61%	44,619	0.08%
81	90	216	18,922	1,418	1.90%	63,541	0.11%
91	100	254	24,657	1,672	2.23%	88,199	0.15%
101	200	4,366	699,216	6,038	8.07%	787,415	1.34%
201	300	7,056	1,816,785	13,094	17.50%	2,604,200	4.43%
301	400	8,172	2,921,611	21,266	28.42%	5,525,811	9.39%
401	500	7,736	3,498,854	29,002	38.76%	9,024,665	15.34%
501	600	7,049	3,916,234	36,051	48.18%	12,940,899	21.99%
601	700	6,144	4,053,702	42,195	56.39%	16,994,601	28.88%
701	800	5,294	4,040,687	47,489	63.46%	21,035,288	35.75%
801	900	4,554	3,948,523	52,043	69.55%	24,983,811	42.46%
901	1,000	3,704	3,596,910	55,747	74.50%	28,580,721	48.57%
1,001	1,500	11,493	14,335,826	67,240	89.85%	42,916,547	72.94%
1,501	2,000	4,647	8,215,729	71,887	96.06%	51,132,276	86.90%
2,001	2,500	1,801	4,117,070	73,688	98.47%	55,249,346	93.90%
2,501	3,000	702	1,965,592	74,390	99.41%	57,214,937	97.24%
3,001	3,500	264	875,299	74,654	99.76%	58,090,236	98.73%
3,501	4,000	106	404,312	74,759	99.90%	58,494,547	99.41%
4,001	4,500	37	161,799	74,797	99.95%	58,656,346	99.69%
4,501	5,000	20	98,108	74,817	99.98%	58,754,455	99.85%
5,001	6,000	12	66,588	74,829	100.00%	58,821,043	99.97%
6,001	7,000	3	19,282	74,832	100.00%	58,840,325	100.00%

Average Customers	6,236
Average kWh per Bill	786
Median kWh	601 - 700

RESIDENTIAL SERVICE TOU (RES-01 TOU)

SUMMER (MAY - OCTOBER)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	6	0	6	0.42%	0	0.00%
1	100	30	1,587	37	2.38%	1,587	0.09%
101	200	65	10,623	101	6.59%	12,210	0.67%
201	300	57	15,435	158	10.30%	27,645	1.52%
301	400	80	29,429	238	15.49%	57,074	3.13%
401	500	70	32,003	308	20.04%	89,078	4.88%
501	600	81	44,413	389	25.30%	133,491	7.32%
601	700	85	55,850	474	30.83%	189,341	10.38%
701	800	98	74,706	572	37.21%	264,047	14.48%
801	900	88	76,195	660	42.96%	340,242	18.65%
901	1,000	96	92,415	756	49.19%	432,657	23.72%
1,001	2,000	549	783,960	1,305	84.93%	1,216,617	66.70%
2,001	3,000	185	435,218	1,490	96.99%	1,651,835	90.56%
3,001	4,000	39	131,352	1,528	99.51%	1,783,187	97.76%
4,001	5,000	6	27,566	1,535	99.93%	1,810,753	99.27%
5,001	10,000	0	0	1,535	99.93%	1,810,753	99.27%
10,001	15,000	1	13,244	1,536	100.00%	1,823,997	100.00%

Average Customers	256
Average kWh per Bill	1,187
Median kWh	1,001 - 2,000

WINTER (NOVEMBER - APRIL)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	13	0	13	0.86%	0	0.00%
1	100	37	1,975	50	3.28%	1,975	0.16%
101	200	92	12,165	143	9.28%	14,140	1.15%
201	300	123	25,681	266	17.32%	39,821	3.24%
301	400	110	33,179	376	24.49%	73,000	5.94%
401	500	134	61,257	510	33.23%	134,256	10.93%
501	600	117	65,459	628	40.87%	199,715	16.25%
601	700	158	105,160	786	51.17%	304,875	24.81%
701	800	113	86,777	899	58.50%	391,652	31.87%
801	900	95	82,926	993	64.66%	474,578	38.62%
901	1,000	83	80,705	1,076	70.05%	555,283	45.19%
1,001	2,000	407	540,816	1,483	96.57%	1,096,099	89.20%
2,001	3,000	48	111,489	1,531	99.69%	1,207,588	98.27%
3,001	4,000	2	8,737	1,534	99.84%	1,216,325	98.98%
4,001	5,000	1	5,239	1,535	99.92%	1,221,564	99.41%
5,001	10,000	1	7,302	1,536	100.00%	1,228,866	100.00%
10,001	15,000	0	0	1,536	100.00%	1,228,866	100.00%

Average Customers	256
Average kWh per Bill	800
Median kWh	601 - 700

RESIDENTIAL SERVICE TOU SUPER PEAK (RES-01 TOU SP)

During the test year there was only 1 bill for Residential Service Time-of-Use Super Peak.
As such, we are not showing a Bill Count exhibit for this class.

RESIDENTIAL SERVICE BRIGHT ARIZONA COMMUNITY SOLAR

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	0	0	0	0.00%	0	0.00%
1	100	3	160	3	0.31%	160	0.02%
101	200	93	14,315	96	10.01%	14,475	1.71%
201	300	103	28,951	199	20.75%	43,426	5.12%
301	400	38	13,473	237	24.71%	56,899	6.71%
401	500	61	27,378	298	31.07%	84,277	9.94%
501	600	78	44,951	376	39.21%	129,228	15.24%
601	700	46	30,085	422	44.00%	159,313	18.79%
701	800	112	84,317	534	55.68%	243,630	28.73%
801	900	82	71,579	616	64.23%	315,209	37.17%
901	1,000	27	25,647	643	67.05%	340,856	40.19%
1,001	1,500	179	212,011	822	85.71%	552,867	65.19%
1,501	2,000	78	133,770	900	93.85%	686,637	80.97%
2,001	2,500	33	73,697	933	97.29%	760,334	89.66%
2,501	3,000	13	34,693	946	98.64%	795,027	93.75%
3,001	4,000	8	26,992	954	99.48%	822,019	96.93%
4,001	5,000	1	4,076	955	99.58%	826,095	97.41%
5,001	6,000	4	21,968	959	100.00%	848,063	100.00%

Average Customers	79
Average kWh per Bill	884
Median kWh	750

SMALL GENERAL SERVICE (SGS-10)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	4,885	0	4,885	4.65%	0	0.00%
1	100	14,297	566,191	19,182	18.27%	566,191	0.48%
101	200	8,608	1,247,256	27,791	26.47%	1,813,447	1.53%
201	300	7,929	1,914,673	35,720	34.02%	3,728,120	3.15%
301	400	7,077	2,395,710	42,797	40.76%	6,123,830	5.17%
401	500	6,153	2,772,029	48,950	46.62%	8,895,858	7.51%
501	600	5,236	2,885,775	54,186	51.61%	11,781,633	9.94%
601	700	4,269	2,784,996	58,455	55.67%	14,566,629	12.29%
701	800	3,710	2,796,953	62,165	59.20%	17,363,582	14.65%
801	900	3,293	2,817,965	65,458	62.34%	20,181,547	17.03%
901	1,000	3,005	2,875,879	68,463	65.20%	23,057,426	19.46%
1,001	1,500	11,116	13,806,031	79,580	75.79%	36,863,457	31.11%
1,501	2,000	7,086	12,387,373	86,666	82.54%	49,250,830	41.56%
2,001	2,500	4,697	10,605,731	91,363	87.01%	59,856,561	50.51%
2,501	3,000	3,483	9,629,831	94,846	90.33%	69,486,392	58.64%
3,001	3,500	2,605	8,521,641	97,451	92.81%	78,008,033	65.83%
3,501	4,000	2,098	7,926,694	99,549	94.81%	85,934,727	72.52%
4,001	4,500	1,392	5,959,139	100,941	96.13%	91,893,866	77.55%
4,501	5,000	1,049	5,018,264	101,990	97.13%	96,912,129	81.78%
5,001	5,500	706	3,737,068	102,696	97.81%	100,649,197	84.94%
5,501	6,000	561	3,254,150	103,257	98.34%	103,903,347	87.68%
6,001	6,500	393	2,480,304	103,650	98.71%	106,383,652	89.77%
6,501	7,000	306	2,083,979	103,956	99.01%	108,467,631	91.53%
7,001	7,500	212	1,551,610	104,168	99.21%	110,019,240	92.84%
7,501	8,000	150	1,149,976	104,318	99.35%	111,169,217	93.81%
8,001	9,000	221	1,793,632	104,539	99.56%	112,962,848	95.33%
9,001	10,000	147	1,323,172	104,686	99.70%	114,286,020	96.44%
10,001	25,000	285	3,409,275	104,971	99.97%	117,695,295	99.32%
25,001	50,000	27	675,040	104,998	100.00%	118,370,335	99.89%
50,001	100,000	2	131,031	105,000	100.00%	118,501,366	100.00%

Average Customers	8,750
Average kWh per Bill	1,129
Median kWh	501 - 600

SMALL GENERAL SERVICE TOU (SGS-10 TOU)

SUMMER (MAY - OCTOBER)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	0	0	0	0.00%	0	0.00%
1	400	4	587	4	8.33%	587	0.57%
401	800	4	2,994	8	16.86%	3,581	3.45%
801	1,200	4	4,186	12	25.39%	7,768	7.48%
1,201	1,600	3	3,966	15	31.78%	11,733	11.29%
1,601	2,000	5	8,933	20	42.44%	20,667	19.89%
2,001	2,400	4	9,003	24	50.97%	29,670	28.56%
2,401	2,800	8	21,943	33	68.02%	51,613	49.68%
2,801	3,200	8	25,906	41	85.08%	77,519	74.62%
3,201	3,600	3	10,705	44	91.47%	88,224	84.93%
3,601	4,000	3	11,438	47	97.87%	99,661	95.94%
4,001	4,400	1	4,221	48	100.00%	103,882	100.00%

Average Customers	8
Average kWh per Bill	2,164
Median kWh	2,001 - 2,400

WINTER (NOVEMBER - APRIL)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	0	0	0	0.00%	0	0.00%
1	400	6	1,054	6	12.50%	1,054	1.34%
401	800	9	5,871	15	31.71%	6,925	8.82%
801	1,200	4	4,007	19	40.24%	10,932	13.92%
1,201	1,600	4	6,167	23	48.78%	17,098	21.77%
1,601	2,000	7	13,922	31	63.72%	31,020	39.49%
2,001	2,400	7	16,552	38	78.66%	47,572	60.56%
2,401	2,800	7	19,960	45	93.60%	67,532	85.97%
2,801	3,200	1	3,278	46	95.73%	70,810	90.15%
3,201	3,600	1	3,688	47	97.87%	74,497	94.84%
3,601	4,000	1	4,051	48	100.00%	78,548	100.00%
4,001	4,400	0	0	48	100.00%	78,548	100.00%

Average Customers	8
Average kWh per Bill	1,636
Median kWh	1,601 - 2,000

INTERRUPTIBLE POWER SERVICE (IPS)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	6	0	6	1.79%	0	0.00%
1	500	29	4,417	35	10.00%	4,417	0.01%
501	1,000	7	5,675	42	12.05%	10,092	0.03%
1,001	1,500	6	8,027	48	13.85%	18,119	0.05%
1,501	2,000	2	3,323	50	14.36%	21,442	0.06%
2,001	2,500	5	12,395	55	15.90%	33,837	0.10%
2,501	3,000	0	0	55	15.90%	33,837	0.10%
3,001	3,500	4	12,029	59	16.92%	45,867	0.13%
3,501	4,000	4	13,865	62	17.95%	59,732	0.17%
4,001	4,500	3	11,537	65	18.72%	71,269	0.20%
4,501	5,000	1	4,406	66	18.97%	75,674	0.21%
5,001	10,000	12	96,679	79	22.56%	172,353	0.48%
10,001	15,000	21	285,877	99	28.46%	458,230	1.29%
15,001	20,000	36	654,671	135	38.72%	1,112,902	3.13%
20,001	25,000	29	667,233	163	46.92%	1,780,135	5.00%
25,001	40,000	37	1,219,421	200	57.44%	2,999,555	8.43%
40,001	55,000	31	1,530,788	231	66.41%	4,530,343	12.74%
55,001	70,000	14	908,370	245	70.51%	5,438,713	15.29%
70,001	85,000	15	1,246,330	261	74.87%	6,685,043	18.80%
85,001	100,000	10	953,434	270	77.69%	7,638,477	21.48%
100,001	125,000	10	1,145,898	280	80.51%	8,784,375	24.70%
125,001	150,000	8	1,144,964	288	82.82%	9,929,340	27.92%
150,001	175,000	4	750,441	293	84.10%	10,679,781	30.03%
175,001	200,000	6	1,239,759	299	85.90%	11,919,540	33.51%
200,001	225,000	7	1,558,193	306	87.95%	13,477,732	37.89%
225,001	250,000	4	1,101,021	311	89.23%	14,578,753	40.99%
250,001	300,000	9	2,507,146	319	91.79%	17,085,899	48.04%
300,001	350,000	6	2,137,824	326	93.59%	19,223,724	54.05%
350,001	400,000	1	355,060	327	93.85%	19,578,783	55.05%
400,001	500,000	2	841,091	328	94.36%	20,419,874	57.41%
500,001	750,000	11	7,057,994	339	97.44%	27,477,868	77.25%
750,001	1,000,000	8	7,107,908	347	99.74%	34,585,776	97.24%
1,000,001	1,250,000	1	982,065	348	100.00%	35,567,841	100.00%

Average Customers	29
Average kWh per Bill	102,206
Median kWh	25,001 - 40,000

PROPOSED MEDIUM GENERAL SERVICE (MGS)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	83	0	83	0.52%	0	0.00%
1	100	91	5,351	174	1.09%	5,351	0.00%
101	200	46	7,027	220	1.38%	12,378	0.00%
201	300	28	7,185	248	1.55%	19,563	0.00%
301	400	12	4,219	259	1.62%	23,782	0.01%
401	500	20	9,529	279	1.75%	33,311	0.01%
501	600	12	6,408	291	1.82%	39,719	0.01%
601	700	13	9,032	304	1.91%	48,751	0.01%
701	800	29	22,422	333	2.09%	71,173	0.02%
801	900	18	15,926	351	2.20%	87,098	0.02%
901	1,000	17	16,767	369	2.31%	103,865	0.03%
1,001	2,000	193	299,007	562	3.52%	402,872	0.10%
2,001	3,000	281	740,859	843	5.28%	1,143,731	0.28%
3,001	4,000	603	2,205,476	1,446	9.05%	3,349,206	0.82%
4,001	5,000	760	3,498,624	2,206	13.81%	6,847,830	1.68%
5,001	6,000	980	5,517,268	3,187	19.95%	12,365,099	3.03%
6,001	7,000	950	6,294,965	4,137	25.90%	18,660,064	4.57%
7,001	8,000	915	6,996,834	5,052	31.63%	25,656,897	6.28%
8,001	9,000	813	7,044,660	5,865	36.72%	32,701,557	8.01%
9,001	10,000	709	6,857,883	6,574	41.16%	39,559,440	9.68%
10,001	11,000	563	6,014,913	7,136	44.68%	45,574,353	11.16%
11,001	12,000	530	6,214,699	7,666	48.00%	51,789,052	12.68%
12,001	13,000	496	6,329,284	8,163	51.11%	58,118,336	14.23%
13,001	14,000	418	5,747,033	8,580	53.72%	63,865,369	15.64%
14,001	15,000	395	5,824,297	8,975	56.19%	69,689,667	17.06%
15,001	16,000	365	5,766,622	9,340	58.48%	75,456,289	18.47%
16,001	17,000	336	5,649,738	9,676	60.58%	81,106,027	19.86%
17,001	18,000	271	4,827,004	9,946	62.27%	85,933,031	21.04%
18,001	19,000	292	5,489,937	10,238	64.10%	91,422,968	22.38%
19,001	20,000	269	5,350,192	10,507	65.79%	96,773,159	23.69%
20,001	30,000	1,947	48,732,443	12,454	77.98%	145,505,602	35.62%
30,001	40,000	1,129	39,555,409	13,583	85.04%	185,061,011	45.31%
40,001	50,000	607	27,473,043	14,190	88.84%	212,534,054	52.03%
50,001	75,000	733	45,473,695	14,923	93.43%	258,007,749	63.17%
75,001	100,000	343	29,948,935	15,265	95.58%	287,956,684	70.50%
100,001	125,000	194	22,057,576	15,459	96.79%	310,014,260	75.90%
125,001	150,000	156	21,944,930	15,616	97.77%	331,959,190	81.27%
150,001	175,000	101	16,723,696	15,717	98.40%	348,682,886	85.36%
175,001	200,000	82	15,524,887	15,798	98.91%	364,207,773	89.17%
200,001	225,000	77	16,533,703	15,875	99.39%	380,741,475	93.21%
225,001	250,000	33	7,880,416	15,908	99.60%	388,621,891	95.14%
250,001	300,000	35	9,511,157	15,942	99.81%	398,133,049	97.47%
300,001	350,000	20	6,696,170	15,962	99.94%	404,829,219	99.11%
350,001	400,000	8	2,828,091	15,970	99.99%	407,657,310	99.80%
400,001	450,000	2	804,986	15,972	100.00%	408,462,296	100.00%

Average Customers	1,331
Average kWh per Bill	25,574
Median kWh	12,001 - 13,000

PROPOSED MEDIUM GENERAL SERVICE TOU (MGS TOU)

SUMMER (MAY - OCTOBER)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	2	0	2	3.57%	0	0.00%
1	25,000	0	0	2	3.57%	0	0.00%
25,001	50,000	19	714,378	21	42.86%	714,378	19.37%
50,001	100,000	15	1,002,862	36	75.00%	1,717,240	46.56%
100,001	150,000	9	1,175,479	45	92.86%	2,892,719	78.43%
150,001	300,000	3	795,717	48	100.00%	3,688,437	100.00%

Average Customers	8
Average kWh per Bill	76,842
Median kWh	50,001 - 100,000

WINTER (NOVEMBER - APRIL)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	2	0	2	3.70%	0	0.00%
1	25,000	2	4,589	4	7.41%	4,589	0.11%
25,001	50,000	23	1,041,323	27	55.56%	1,045,913	25.95%
50,001	100,000	7	508,865	34	70.37%	1,554,777	38.58%
100,001	150,000	11	1,556,800	44	92.59%	3,111,577	77.20%
150,001	300,000	4	918,942	48	100.00%	4,030,519	100.00%

Average Customers	8
Average kWh per Bill	83,969
Median kWh	25,001 - 50,000

PROPOSED LARGE GENERAL SERVICE (LGS)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	3	0	3	1.23%	0	0.00%
1	100,000	1	43,482	3	1.64%	43,482	0.05%
100,001	200,000	20	2,935,777	23	11.48%	2,979,259	3.12%
200,001	300,000	35	8,892,915	59	28.69%	11,872,173	12.44%
300,001	400,000	49	17,338,992	108	52.87%	29,211,165	30.62%
400,001	500,000	24	10,924,531	132	64.75%	40,135,697	42.07%
500,001	750,000	39	23,684,124	171	84.02%	63,819,821	66.89%
750,001	1,000,000	22	18,746,093	193	94.67%	82,565,914	86.54%
1,000,001	1,500,000	11	12,846,390	204	100.00%	95,412,304	100.00%

Average Customers	17
Average kWh per Bill	467,707
Median kWh	300,001 - 400,000

PROPOSED LARGE GENERAL SERVICE TOU (LGS TOU)

SUMMER (MAY - OCTOBER)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	0	0	0	0.00%	0	0.00%
1	400,000	0	0	0	0.00%	0	0.00%
400,001	600,000	4	2,009,306	4	30.00%	2,009,306	25.49%
600,001	800,000	7	4,785,802	11	90.00%	6,795,108	86.19%
800,001	1,000,000	1	1,088,491	12	100.00%	7,883,600	100.00%

Average Customers	2
Average kWh per Bill	656,967
Median kWh	600,001 - 800,000

WINTER (NOVEMBER - APRIL)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	0	0	0	0.00%	0	0.00%
1	400,000	0	0	0	0.00%	0	0.00%
400,001	600,000	3	1,398,841	3	25.00%	1,398,841	18.57%
600,001	800,000	9	6,135,824	12	100.00%	7,534,664	100.00%
800,001	1,000,000	0	0	12	100.00%	7,534,664	100.00%

Average Customers	2
Average kWh per Bill	627,889
Median kWh	600,001 - 800,000

PROPOSED LARGE POWER SERVICE (LPS)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	0	0	0	0.00%	0	0.00%
1	500,000	12	4,663,335	12	33.33%	4,663,335	8.07%
500,001	1,000,000	2	1,793,146	14	38.89%	6,456,481	11.18%
1,000,001	1,500,000	7	9,518,135	21	58.33%	15,974,616	27.65%
1,500,001	2,000,000	3	4,561,807	24	66.67%	20,536,423	35.55%
2,000,001	3,000,000	4	11,171,462	28	77.78%	31,707,885	54.89%
3,000,001	4,000,000	8	26,060,573	36	100.00%	57,768,457	100.00%

Average Customers	3
Average kWh per Bill	1,604,679
Median kWh	1,000,001 - 1,500,000

REDACTED

PROPOSED LARGE POWER SERVICE TOU (LPS TOU)

SUMMER (MAY - OCTOBER)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	xx	xx	xx	xx	xx	xx
1	2,000,000	xx	xx	xx	xx	xx	xx
2,000,001	3,000,000	xx	xx	xx	xx	xx	xx
3,000,001	4,000,000	xx	xx	xx	xx	xx	xx

Average Customers	xx
Average kWh per Bill	xx
Median kWh	xx

WINTER (NOVEMBER - APRIL)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	xx	xx	xx	xx	xx	xx
1	2,000,000	xx	xx	xx	xx	xx	xx
2,000,001	3,000,000	xx	xx	xx	xx	xx	xx
3,000,001	4,000,000	xx	xx	xx	xx	xx	xx

Average Customers	xx
Average kWh per Bill	xx
Median kWh	xx

Customer specific information that could be considered confidential has been redacted and will be provided pursuant to the terms of the Protective Agreement in this docket.

LIGHTING SERVICE (LTG)

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	0	0	0	0.00%	0	0.00%
1	10	39	309	39	0.14%	309	0.01%
11	20	145	1,975	184	0.64%	2,284	0.08%
21	30	99	2,586	283	0.99%	4,870	0.17%
31	40	10,574	386,083	10,857	38.02%	390,952	13.83%
41	50	7,344	327,562	18,201	63.74%	718,514	25.41%
51	60	1,989	104,269	20,190	70.71%	822,783	29.10%
61	70	897	59,362	21,087	73.85%	882,145	31.20%
71	80	1,189	90,533	22,276	78.01%	972,679	34.40%
81	90	1,439	123,102	23,715	83.05%	1,095,781	38.76%
91	100	739	71,050	24,454	85.64%	1,166,831	41.27%
101	200	2,503	338,827	26,957	94.40%	1,505,658	53.26%
201	300	567	135,273	27,524	96.39%	1,640,931	58.04%
301	400	312	108,690	27,836	97.48%	1,749,621	61.88%
401	500	178	79,082	28,014	98.11%	1,828,703	64.68%
501	600	102	55,754	28,116	98.46%	1,884,457	66.65%
601	700	64	41,665	28,180	98.69%	1,926,122	68.13%
701	800	45	33,906	28,225	98.84%	1,960,027	69.33%
801	900	43	36,545	28,268	98.99%	1,996,573	70.62%
901	1,000	39	37,019	28,307	99.13%	2,033,592	71.93%
1,001	2,000	146	204,336	28,453	99.64%	2,237,927	79.16%
2,001	3,000	50	120,551	28,503	99.82%	2,358,479	83.42%
3,001	4,000	17	58,502	28,520	99.88%	2,416,981	85.49%
4,001	5,000	10	44,258	28,530	99.91%	2,461,239	87.05%
5,001	10,000	1	5,635	28,531	99.92%	2,466,874	87.25%
10,001	15,000	14	188,210	28,545	99.96%	2,655,084	93.91%
15,001	20,000	10	172,167	28,555	100.00%	2,827,250	100.00%

Average Customers	2,388
Average kWh per Bill	99
Median kWh	41 - 50

Overhead Services	Number of Items	Wattage
New 30' Wood Pole (Class 6)	8,574	
New 30' Metal or Fiberglass	5,829	
100 watt Bulb	25,609	2,560,900
150 watt Bulb	9,080	1,362,000
200 watt Bulb	6,424	1,284,800
250 watt Bulb	2,837	709,250
400 watt Bulb	1,274	509,600

Underground Services	Number of Items	Wattage
Existing Wood Pole	372	
New 30' Wood Pole (Class 6)	176	
New 30' Metal or Fiberglass	2,699	
100 watt Bulb	5,670	567,000
150 watt Bulb	230	34,500
200 watt Bulb	336	67,200
250 watt Bulb	1,152	288,000
400 watt Bulb	268	107,200

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 FOR RELATED APPROVALS.)	DOCKET NO. E-04204A-15-______

Direct Testimony of

David G. Hutchens

on Behalf of

UNS Electric, Inc.

May 5, 2015

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is David G. Hutchens. My business address is 88 East Broadway Blvd., Tucson, Arizona 85701.

Q. What is your position with UNS Electric, Inc. ("UNS Electric" or the "Company")?

A. I am the Chief Executive Officer and President of UNS Electric, Inc. ("UNS Electric") as well as for UNS Energy Corporation ("UNS Energy"), Tucson Electric Power Company ("TEP"), UniSource Energy Services ("UES"), and UNS Gas, Inc. ("UNS Gas").

Q. Please describe your background and work experience.

A. I received a Bachelor of Science degree in Aerospace Engineering from the University of Arizona in 1988 and a Master of Business Administration degree from the University of Arizona's Eller Graduate School of Management in 1999.

I was commissioned into the United States Navy in 1988 and served as a Nuclear-Trained Submarine Line Officer until 1993.

I was hired by TEP in 1995 as an Analyst in Product Planning and Development. In 1996, I moved into TEP's Wholesale Marketing Department as an Energy Marketer/Trader. I was promoted to Supervisor of the area in 1999, Manager in 2001, and General Manager in 2003. I was promoted to Vice President of Wholesale Energy and of UNS Gas, Inc. ("UNS Gas") in 2007 and to Vice President of Energy Efficiency and Resource Planning in 2009. In 2011, I was promoted to Executive Vice President of UNS Energy and TEP; in December 2011, I was promoted to President of UNS Energy and TEP. In 2014, I was promoted to my current position of President and Chief

Executive Officer of UNS Energy, TEP and Unisource Energy Services.

Q. What is the purpose of your Direct Testimony?

A. My testimony covers the following topics:

- A summary of UNS Electric's rate request.
- The importance of the Company's acquisition of 25% of Gila River Power Plant Unit 3 ("Gila River") and why the facility should be placed in rate base.
- Rate changes designed to more closely reflect the cost of the services customers receive from the electric system, to mitigate the cost shift between and within classes of customers and to provide the Company with an appropriate opportunity to recover its fixed infrastructure costs.
- A new rate aimed at promoting economic development in UNS Electric's service territory.

II. RATE REQUEST OVERVIEW.

Q. Why are new rates necessary?

A. The rates proposed in this application are needed to allow UNS Electric to preserve safe, reliable and affordable electric service in an evolving energy marketplace.

Since June 2012, the end of the test year used to establish current rates, the Company has updated its transmission and distribution infrastructure and invested significantly in a clean, efficient generating portfolio that will provide customers with a more stable source of power for decades to come. By generating more of its own power, UNS Electric can better insulate customers from wholesale market fluctuations and other energy supply risks. While the cost of this investment would increase non-fuel base rates under the

Company's proposal, it also would reduce fuel and purchased power costs – an exchange that will provide customers with greater rate stability.

Our proposal seeks to recover those and other costs though revised rates that reflect the new realities of our industry. In the past, Arizona utilities could count on annual increases in energy usage to produce revenue that pays for infrastructure investments. But economic forces have combined with energy efficiency improvements and other factors to reverse that historic trend. UNS Electric's customers are using less energy, and increasing numbers of them are generating a portion of their own power from solar distributed generation ("DG") systems. Yet they remain equally and entirely dependent on utility systems that must be maintained and improved to accommodate new operational needs and regulatory requirements.

While all customers depend on these improvements, some don't pay for their fair share of them due to rates that are designed to recover fixed system costs through usage-based charges. In this proceeding, UNS Electric seeks approval for 21st century rates that would accommodate changing usage patterns, recover costs more equitably, promote economic development and help us maintain safe, reliable and affordable electric service for the benefit of all our customers.

Q. Please describe the Company's revenue request.

A. UNS Electric's request would result in a retail revenue **reduction** of approximately $5.8 million, or 3.6 percent, in the first year after new rates take effect. This initial decrease reflects the impact of a proposed one-year credit to the purchased power and fuel adjustment clause ("PPFAC") due to deferred savings from Gila River. Once that temporary credit expires – one year after new rates take effect – the company's proposal would increase retail revenues by approximately $3.5 million, or 2.1%.[1] The changes reflect several factors, including (i) higher non-fuel revenues, (ii) lower fuel and purchased power costs and (iii) changes to revenues collected in adjustor mechanisms.

Q. Please describe the bill impact for the average residential customer.

A. The temporary PPFAC credit described above would mitigate the immediate impact of our rate request. If new rates are approved by the date requested in this application (April 30, 2016), average residential bills would increase by $1.99 per month in May 2016 and by an additional $7.87 per month in May 2017.[2]

Q. How would the Company's proposed rates affect large commercial customers' bills?

A. Under the Company's proposal, the following customer classes would experience a reduction in their monthly bills: medium general service; large general service and large power service.[3]

Q. Why would the bills of large commercial customers decrease while residential bills increase?

A. As more fully described in the Direct Testimony of Craig A. Jones, the Company's current rate design allows residential customers to pay far less than the cost required to serve them while large customers pay more than the cost required to serve them. The Company's proposed rate design changes would better align rates with the costs incurred to serve different types of customers.

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[1] See Direct Testimony of Dallas J. Dukes for an explanation of the deferred savings related to Gila River as well as the Company's proposed revenue requirement.
[2] See Direct Testimony of Craig A. Jones
[3] See the Direct Testimony of Craig A. Jones

Q. **Do you have information that would demonstrate this mismatch in costs and rates?**

A. Yes. In addition to the cost of service study referenced in the Direct Testimony of Craig A. Jones, a comparison of the Company's rates to those charged by other regional utilities provides evidence that UNS Electric needs to address the difference in its residential and industrial/large commercial customer rates. While UNS Electric's residential rates are among the lowest in the region, the same cannot be said for the rates charged to large commercial customers.

Q. **Please describe the key elements driving the Company's request.**

A. The key elements are described below.

- **Gila River.** The $55 million purchase of this 137-megawatt ("MW") resource has provided UNS Electric with its first and only base-load generating resource. Ownership of the unit provides many benefits to our customers, the most significant being long-term rate stability through the use of a highly efficient, combined cycle natural gas plant.
- **Retail Sales Reductions.** UNS Electric's test year retail sales are nearly 8% *below* the level from the June 30, 2012 test year used in the Company's last rate case, due in part to a 50% reduction in sales to industrial and mining customers. Residential usage per customer fell nearly 4% between 2012 and 2014 and is expected to decline again in 2015. The significant decline in sales is due to several factors, including: (i) the shutdown or curtailment of operations by certain large customers; (ii) the effects of increased energy efficiency ("EE") and DG; and (iii) the slow pace of economic recovery. Sales reductions resulting from successful EE measures and DG systems were exacerbated by business closures, including the 2014 bankruptcy of UNS Electric's largest customer, Mercator Minerals. Due to lower overall sales, the Company must recover its fixed costs over fewer kilowatt hours ("kWh").

Q. What elements of the Company's proposal mitigate the bill impact of its request?

A. The Company's request includes (i) a reduction in UNS Electric's depreciation expense,[4] based on an updated depreciation study, and (ii) an estimated $9.3 million credit to the PPFAC related to deferred fuel, purchased power, transmission and capacity savings resulting from ownership of Gila River.[5] I also would like to point out that the average cost of debt used in the Company's revenue requirement of 4.66% is 22% *lower* than the cost of debt approved in our last rate case. This reduction in the Company's debt costs resulted from constructive regulatory outcomes, steady improvement in UNS Electric's financial condition, a strong credit rating and favorable capital market conditions. UNS Electric's increase to an A3 rating after being acquired by Fortis Inc.[6] puts the Company in position to access the capital markets on favorable terms, which will help to reduce the amount of future borrowing costs that need to be recovered from customers.

Q. Why has the Company proposed rate design changes?

A. The primary objectives of the proposed rate design changes are summarized below.

- **To align rate structures with our customers' evolving energy use.** The Company must update its rate structures to more closely match the price our customers pay to the cost of the service they receive. For example, our rates do not appropriately charge solar DG customers for their use the Company's electric system to (i) sell excess energy when their solar arrays' output exceeds their demand and (ii) receive energy when their solar arrays' output falls short of their demand.

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[4] See the Direct Testimonies of Dr. Ronald E. White and Kentton C. Grant.

[5] See the Direct Testimony of Dallas J. Dukes.

[6] The Commission approved the acquisition of UNS Energy by Fortis Inc. ("Fortis") in Decision No. 74689 (August 12, 2014). During the acquisition proceedings, UNS Energy indicated that the Fortis acquisition would deliver numerous benefits, including the potential for an improvement in the credit ratings of TEP, UNS Gas, and UNS Electric. Following the acquisition, Moody's Investor Services upgraded the unsecured bond ratings of each of those companies to A3.

- **To reduce the level of cross-subsidies between customers.** UNS Electric seeks to fairly and consistently apply rates across all of our customer classes based on the cost of providing service to each customer group.
- **To give the Company an appropriate opportunity to recover its fixed costs.** Current rates for more than 95% of UNS Electric's customers are designed to collect a majority of the Company's fixed costs through volumetric charges based on electric consumption. UNS Electric is proposing rate design changes that will provide more equitable cost recovery in an environment where overall electricity sales are declining yet the requirements on its system have increased.

Q. You previously mentioned that retail sales declined as a result of business closures and the slow pace of economic recovery. Does the Company's application include any proposals to help promote economic development in UNS Electric's service territory?

A. Yes. The Company is proposing a new Economic Development Rate ("EDR") intended to attract new businesses and support local economies. EDRs provide discounted electricity rates to new or existing businesses that meet certain qualifications (such as job creation or minimum load requirements).[7] Utilities offer EDRs to (i) attract new business to their service territory and (ii) encourage existing customers to expand their operations within the utility's service territory.

Q. Why should the Commission or utilities support economic development?

A. Economic growth provides a wide range of public benefits, including stable electric rates. Manageable customer and sales growth allows utilities to operate their systems more efficiently while spreading the fixed costs among a greater number of customers, thus mitigating the magnitude and frequency of rate case filings. The Company believes it can

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[7] See Direct Testimony of Dallas J. Dukes.

play a bigger role in attracting and promoting the growth of businesses in its service territories if the Commission approves an EDR.

III. GILA RIVER.

Q. Why did UNS Electric purchase an interest in Gila River Unit 3?

A. The acquisition of Gila River was a unique opportunity to partner with TEP, UNS Electric's sister company, to purchase one of the newest and most efficient power plants in Arizona. The partnership with TEP provided numerous benefits to UNS Electric that, due to the Company's relatively small size, would not have been available otherwise. Specifically, the purchase of Gila River provided UNS Electric with the opportunity to: (i) acquire an optimal amount of generating capacity at a very favorable price; (ii) diversify its resource portfolio by acquiring its first base-load generating resource; and (iii) provide long-term rate stability to customers.

Prior to the acquisition of Gila River, UNS Electric did not own *any* base-load generating capacity and relied heavily on purchased power to supply the vast majority of the Company's resource needs. The ownership of Gila River reduces the Company's reliance on the wholesale power markets, limiting its customers' exposure to unpredictable swings in wholesale market conditions. Finally, the $398 cost per kW to acquire Gila River was significantly lower than the estimated cost of $1,367 per kW to build a new unit, allowing the Company to avoid a higher rate impact for customers.[8]

[8] See the Direct Testimony of Michael Sheehan.

Q. Did the acquisition of Gila River influence the timing of UNS Electric's rate case application?

A. Yes. In January 2015, in Decision No. 74911 (January 22, 2015), the Commission acknowledged that the financial cost of acquiring and operating Gila River is substantial and may detrimentally impact the Company's financial position. For those reasons, the Commission authorized UNS Electric to defer certain costs and savings. The deferral of non-fuel costs will expire on April 30, 2016 and is limited to $10.5 million or the cumulative deferred savings at that date.

Given the relative size of this investment, it is vital that UNS Electric begin recovering the return on and of this investment, as well as the non-fuel operating expense related to the facility, through non-fuel base rates no later than May 1, 2016.

Q. Why should the costs associated with owning and operating Gila River be included in UNS Electric's base rates?

A. There are several factors supporting the Company's position that the purchase of Gila River was prudent and is in the public interest, including: i) Gila River is an economic, highly efficient source of base-load power for customers; (ii) the purchase was significantly less expensive than other options analyzed by the Company, including building a new unit; and (iii) ownership of Gila River reduces the Company's reliance on wholesale power markets, reducing customers' exposure to unpredictable swings in power prices. Moreover, testimony filed by Staff and RUCO in a separate docket acknowledges the customer benefits of Gila River, while the Commission also recognized the benefits of Gila River in Decision No. 74911:

> UNSE has shown, and Staff and RUCO agree, that the acquisition of the Gila River Unit 3 is likely to benefit the Company and ratepayers by providing an efficient and economical source of baseline power, but that the financial cost of acquiring and operating UNSE's share in Gila Unit 3 is substantial and may detrimentally impact the Company's financial

> condition. The accounting order is intended as a bridge to maintain UNSE's financial condition until its next rate case. (at Page 10)

The Company recognizes, however, that Decision No. 74911 makes no finding concerning the prudence of UNS Electric's purchase of Gila River.

IV. PROPOSED RATE DESIGN CHANGES AND NEW RATE OFFERINGS.

Q. Please explain UNS Electric's three-part rate design proposal.

A. Under the proposed three-part rate design, customer bills would include (i) a basic service charge to recover some fixed costs, such as the meter, service lines, customer service and billing functions, and minimum distribution system costs; (ii) a demand charge to send appropriate cost-of-service price signals and allow for recovery of fixed transmission and generation costs necessary to satisfy a customer's maximum electric demand over a specific period of time; and (iii) an energy charge to recover fuel and purchased power expenses attributable to the amount of electricity used by the customer. The three-part rate design would be mandatory for all new DG and other partial requirements customers and would be available as an option for non-DG customers. The Company believes that a three-part rate design sends more appropriate price signals, allows customers to reduce their bills by managing their energy consumption through EE or DG, and helps mitigate the DG cost shift by better aligning rates with the way customers use the Company's electric system.

Q. Briefly describe the Company's rationale for its rate design proposals.

A. The Company is proposing rate design changes that are intended to (i) align rate structures with our customers' evolving use of power and the electric system; (ii) send appropriate price signals that more accurately reflect the cost of the service customers are receiving from the electric system; and (iii) give the Company an appropriate opportunity to recover its fixed costs of providing safe and reliable electric service.

- **Fixed cost recovery**. As I previously mentioned, UNS Electric's test year retail sales are nearly 8% *below* those from the test year used in the Company's last rate case. The decline in sales is due to several factors, including: (i) the shutdown or curtailment of operations by certain large customers; (ii) the Commission's EE and DG requirements; and (iii) the slow pace of economic recovery. UNS Electric's current rate design relies heavily on volumetric sales to recover a majority of its fixed costs. This outdated model is no longer appropriate at a time when usage per customer is expected to decline, driven by increasingly successful EE programs and growing DG usage. Absent any change in the current rate designs, the Company will not have an opportunity to recover its costs and earn an appropriate return on its investments.
- **Alignment of rates with system usage.** The rapid expansion of rooftop solar has changed the way that many customers use and access the Company's distribution and generation system. UNS Electric must invest in the necessary infrastructure to deliver safe, reliable service to every customer, 24 hours a day, 7 days a week – regardless of whether some customers can meet some of those needs with a solar array some of the time. The Company's current rate design unfairly shifts costs from DG users to other customers. In Decision No. 74202 (December 3, 2013) involving Arizona Public Service Company ("APS"), the Commission found that the expansion of DG systems in APS's service territory "results in a cost shift from APS's DG Customers to APS's non DG residential customers absent significant changes to APS's rate design."[9] It is in the public interest to expeditiously address this cost shift in order to more equitably allocate the cost of the electric system across all customers.

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[9] See Decision No.74202, Finding of Fact 49.

Q. Please describe your proposals to improve the Company's fixed cost recovery.

A. The Company is proposing the following rate design changes.

- **Basic Service Charge.** Based on the results of its cost of service study, the Company is recommending a residential basic service charge of $20 per month. UNS Electric estimates that, on average, it must collect approximately $54 per month from residential customers to recover all of the fixed costs associated with providing them with electric service.[10] The Company's proposal to increase the basic service charge is an important step toward aligning prices with service costs. By reducing reliance on volumetric charges to recover fixed costs, it also represents an appropriate and necessary response to sales reductions resulting from expanding EE and DG use.
- **Demand Charge.** The Company's proposal includes a mandatory three-part rate design for new residential DG users and new small commercial DG users. This rate design also would be an option for other residential and small commercial customers. The three parts include a basic service charge, a demand charge and an energy charge.[11] If designed properly, a demand charge can provide customers with a price signal that accurately reflects the cost of the system that must be available to serve their individual peak load while affording the Company a better opportunity to recover fixed system costs.
- **Rate Tiers.** The Company's current rates include higher kWh charges at higher levels of consumption – a feature typically described as an inclining block structure. This type of rate design was first implemented when economic growth and higher residential consumption levels resulted in sales of electricity increasing year after year, providing electric utilities with a fair opportunity to recover fixed

[10] See Direct Testimony of Craig A. Jones.
[11] See Direct Testimony of Dallas J. Dukes.

system costs. However, the "new normal" of flat or declining sales – resulting primarily from the use of EE and DG – limits the Company's opportunity to recover its costs through rates that feature an inclining block structure. This problem is exacerbated by DG customers whose energy usage rarely reaches the upper rate tiers, thus shifting fixed costs to other customers who use more energy. UNS Electric is proposing to eliminate certain upper tiers to reduce this cost shift and enhance the Company's ability to recover its fixed costs.

Q. Why is it important to align rate design with customers' use of the system?

A. I believe that all customers should pay their fair share of the Company's service costs. For example, solar DG users depend on the Company throughout the day to supplement and stabilize their solar arrays' intermittent output. While they take less power from UNS Electric when sunlight is powering their solar panels, they rely heavily on the utility system during the late afternoon, when solar output wanes and use of the Company's system typically reaches its peak. DG customers also rely on the Company to manage excess energy from their systems.

The level of service UNS Electric provides to solar DG customers is even greater than other customers receive, since the Company must manage the intermittent and unpredictable push and pull of electricity from their solar arrays. Yet under the Company's current rates, which feature a tiered rate design that relies heavily on volumetric sales to recover fixed costs, solar DG users are not asked to pay for their fair share of the electric system. Instead, those costs are shifted to other customers.

UNS Electric must build and maintain its system to meet the peak demand of *every* customer, regardless of the technologies or supplemental energy sources they may use. Therefore, every customer should pay an equitable price for their use of that system.

Q. Has the Commission, ACC Staff or other stakeholders acknowledged the cost shift described above?

A. Yes. The following is an excerpt from a memo written by ACC Staff to the Commission.

> "With increasing levels of DG penetration, the potential of shifting costs from customers with DG systems to those customers without such systems becomes apparent. As more customers offset a portion of their monthly bills by using energy produced by their DG systems, they purchase less energy from the utility. Because residential rates are typically designed to recover much of the utility's fixed costs through volumetric energy rates, DG customers effectively pay less of these fixed costs. The additional fixed costs then must be picked up by non-DG customers either through higher energy rates or through other mechanisms..."[12]

The Commission also acknowledged the DG cost shift. In Decision No. 74202, the Commission approved a $0.70 per kW per month DG adjustment for APS customers who installed DG systems after December 31, 2013.

Q. Would the higher basic service charge and three-part rate design in your proposal provide for the recovery of *all* of the Company's fixed costs or eliminate the DG cost shift?

A. No. In the interests of gradualism, we have not asked to increase the basic service charge to a level that would recover all of the Company's fixed service costs, or even those fixed costs associated with local distribution services. As a result, our proposed rates would continue to recover <u>some</u> fixed costs through volumetric charges, preserving the conditions that shift some costs from DG system users to other customers. This cost shift would be exacerbated by the continued use of current net metering rules that allow DG system users to trade excess solar energy for free, on-demand utility service.

[12] Memorandum from ACC Utilities Division Staff to the Commission, dated September 30, 2013 (Docket No. E-01345A-12-0248)

Q. Is the Company proposing any other changes that will help further mitigate the DG cost shift?

A. Yes. The Company is requesting approval of (i) a new Net Metering tariff for new DG system users that provides monthly bill credits for any excess energy produced from an eligible DG facility and (ii) a partial waiver of the Commission's Net Metering Rules.[13]

Q. Please describe the Company's proposed Net Metering Tariff.

A. The new Net Metering tariff will modify how new DG customers receive credit for excess energy that is generated by their DG system and delivered to UNS Electric.

Under the new tariff:

- New DG customers would continue to receive a full retail rate offset for the energy they consume from their DG system.
- New DG customers would pay the currently approved and applicable retail rate for all energy delivered by UNS Electric.
- New DG customers would be compensated for any excess energy their DG system produces and delivers to the Company with bill credits calculated using the Renewable Credit Rate.
- New DG customers could carry over unused bill credits to future months if they exceed the amount of their current UNS Electric bill.
- The Renewable Credit Rate would be reset each calendar year.

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[13] The Company filed an application on March 25, 2015 containing similar requests (Docket No. E-04204A-15-0099). However, on April 20, 2015, UNS Electric filed a motion to withdraw its net metering application as an acceptance of Commission Staff's April 14, 2015 request to consolidate the matter in a rate case proceeding. On April 28, 2015 the administrative law judge assigned to this docket issued a procedural order granting the motion to withdraw the Company's application.

Q. What is the Renewable Credit Rate?

A. The proposed Renewable Credit Rate, which would be reset annually, is the rate equivalent to the most recent utility scale renewable energy purchased power agreement connected to the distribution system of TEP.[14]

Q. Is the Company requesting that the Commission take action on its rate application by a certain date?

A. Yes. UNS Electric respectfully requests that the Commission issue a final order in this case on or before April 30, 2016.

Q. What is the significance of April 30, 2016?

A. In Decision No. 74911, the Commission authorized UNS Electric to defer certain costs and savings related to Gila River until the earlier of April 30, 2016 or the date that new rates become effective. Given the relative size of this investment to the Company's total OCRB, it is vital that UNS Electric begin recovering the costs of owning and operating Gila River in order to continue maintaining UNS Electric's financial integrity. As a result, the Company respectfully requests that the Commission issue an order in this matter on or before April 30, 2016.

Q. Does this conclude your testimony?

A. Yes.

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[14] See Direct Testimony of Carmine Tilghman.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE – INTERIM CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
VACANT

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

EXHIBIT
UNSE-4
ADMITTED

Rebuttal Testimony of

David G. Hutchens

on Behalf of

UNS Electric, Inc.

January 19, 2016

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

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

Q. Did you file Direct Testimony in this proceeding?

A. Yes.

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

A. My Rebuttal Testimony is filed on behalf of UNS Electric, Inc. ("UNS Electric" or the "Company").

Q. How is your Rebuttal Testimony organized?

A. My testimony is organized as follows:

Section II. The Company's current position on three-part rates.
Section III. Response to Staff's Testimony.
Section IV. Limited response to RUCO's testimony.
Section V. Net metering proposal.
Section VI. The Company's current position on revenue requirement.
Section VII. Economic Development Rate.

II. THE COMPANY SUPPORTS THREE-PART RATES FOR ALL RESIDENTIAL AND SMALL GENERAL SERVICE CUSTOMERS.

Q. Briefly summarize the Company's current position on three-part rates.

A. In our Direct Testimony, the Company proposed (i) mandatory three-part rates for all residential and small commercial customers who installed distributed generation after June 1, 2015 (collectively, "New DG Customers") and (ii) optional three-part rates for non-DG residential and small general service customers.

As I describe later in my testimony, the Company now supports Staff's proposed migration of all residential and small general service ("SGS") customers to three-part rates.

Q. Why is the Company supporting three-part rates for all residential and SGS customers?

A. Simply stated, we need rates that reflect reality. Our current rates were designed for use in an earlier era with different technology, energy usage patterns, economic trends and public policy priorities. We need a sustainable rate structure that is well adapted to current conditions as well as the opportunities and challenges our industry will face going forward. We could try to achieve this objective through adjustments to our current two-part rates, such as higher basic service charges, minimum bills and declining block volumetric rates. But our proposed three-part rate represents a clear step forward to a more equitable, sustainable rate structure, and we support Staff's recommendation that we take that step now for all residential and SGS customers.

A Three-Part Rate Structure is a Sustainable Pricing Model.

Three-part rates (i) can be applied equitably to various types of customers with varying energy demands, (ii) encourage the adoption of emerging technologies such as energy storage and demand-based energy efficiency, and (iii) provide flexibility to meet future changes in the way customers use energy and access the grid. Over time, each component of the three-part rate can be modified to respond to changes in our customers' energy needs while sending more accurate cost-based price signals.

Three-part rates promote fairness and equity.

Three-part rates are fair in that they send accurate, cost-based price signals to all customers. Unlike two-part volumetric rates, three-part rates allow utilities to match the price they charge customers with the way the utility system must be built and maintained. Regardless of technology developments and changing usage patterns, a utility must have facilities in place to safely and reliably meet the maximum demand of every customer, 24 hours a day, 365 days a year. Even if a customer's maximum usage occurs only once or twice a year, we must have the resources in place to meet that demand. A demand charge, by definition, captures and appropriately allocates these infrastructure costs to customers more accurately than usage charges, thus mitigating inter- and intra-class subsidies.

Properly designed three-part rates will send accurate economic signals that promote more cost-effective energy options to all our customers, ultimately leading to more efficient use of the grid and energy resources.

Q. Please provide your general thoughts on the Intervenor rate design testimony filed in this proceeding as it relates to UNS Electric's proposals for three-part rates and net metering.

A. I am pleased that certain parties acknowledge the need to modernize UNS Electric's rate structure in light of our customers' evolving use of electricity and the grid. These parties include ACC Staff[1], RUCO[2], Arizona Investment Council ("AIC")[3] and Arizona Public Service ("APS").[4]

The testimonies filed by the Alliance for Solar Choice ("TASC"), Vote Solar and the Arizona Utility Ratepayer Alliance ("AURA") ignore the very real cost shift that is occurring between DG and non-DG customers. Their testimonies also failed to offer any alternatives to the Company's net metering proposal.

In this proceeding, the Company is attempting to modify its rates to (i) recover costs more equitably, (ii) provide flexibility to accommodate changing customer usage patterns, (iii) encourage the integration of new energy technologies into the electric system, (iv) promote the efficient use of the Company's electric system, and (v) ensure the continued provision of safe, reliable and affordable electric services for the benefit of all of our customers.

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[1] Direct Rate Design Testimony of Thomas M. Broderick ("Broderick"), Executive Summary.
[2] Direct Testimony of Lon Huber ("Huber"), page 10 lines 2-3.
[3] Direct Testimony of Daniel G. Hansen, page 20 lines 15-22, page 21 lines 1-5.
[4] Direct Testimony of AhmadFaruqui ("Faruqui") page 13 lines 21-27 page 14; Direct Testimony of Charles A. Miessner, page 4 lines 6-22.

III. RESPONSE TO STAFF'S TESTIMONY.

Q. Have you reviewed Staff's rate design testimony?

A. Yes, I have.

Q. Does the Company support Staff's rate design recommendation to migrate all of UNS Electric's residential and SGS customers to a new tariff that includes a demand charge?

A. Yes. If such rates are properly designed, the Company fully supports transitioning all of our residential and SGS customers to three-part rates.

Q. Did the Company consider a similar proposal in this proceeding?

A. Yes. The Company firmly believes that three-part rates provide fair and equitable price signals while offering the flexibility to meet our customers' evolving energy needs. We stopped short of proposing their mandatory use in part because, when we were preparing this rate filing in 2014 and 2015, the Company did not have the meters in place to implement three-part rates for all residential and SGS customers. With that in mind, we felt like our proposals in this case to (i) increase the basic service charge, (ii) eliminate the third tier in the Company's inclining block volumetric rate structure, (iii) implement three-part rates and a new net metering tariff for new DG customers, and (iv) make three-part rates optional for all customers, would represent progress toward the future introduction of three-part rates for all customers. Company witness Dallas Dukes alludes to this in his Direct Testimony.

> Although UNS Electric is proposing a three-part rate structure as an option, it is not proposing to require all residential and small commercial customers to migrate to a three-part rate structure... UNS Electric is

requesting to begin moving toward a more balanced rate structure that would make such a move possible in the future.[5]

Q. What rationale does Staff provide for transitioning all residential and SGS customers to three-part rates?

A. Staff provides the following explanation for its recommendation regarding three-part rates.

> A three-part rate design better informs customers who are considering adopting new technologies, including DG, about the utility bill impact of their technology choices prior to purchase and installation. A three-part rate design makes significant progress toward addressing essentially all of the issues presented by the difficult transition underway to new DG technologies.
>
> A demand charge is a proven successful rate design component which better reflects cost causation than rate designs which rely upon energy charges only to recovery utility fixed costs. Metering and communications technology improvements, DG penetration, and recent regulatory issues have made its adoption for residential and small general service customers possible, appropriate, timely and even necessary.[6]

Q. Do you agree with Staff's rationale?

A. Yes, I do. The public interest is not well served by clinging to an outdated rate design that does not properly address changes in the industry and that results in inaccurate price signals and increasingly inequitable cost allocations. Properly designed three-part rates provide many benefits, ranging from charging customers more equitably for electric service to encouraging the integration of new technologies, as described by APS witness Ahmad Faruqui.

> Now is the time to take advantage of this opportunity to make cost-reflective three-part rates a standard offering for all residential customers. These rates will recover costs from customers in an equitable manner by more accurately charging customers for their use of the power grid. A more cost-reflective rate will also encourage the adoption of emerging

[5] Direct Testimony of Dallas J. Dukes, page 18, lines 8-13.
[6] Broderick, page 2, lines 5-9 and 20-25.

> energy technologies and changes in energy consumption behavior that will lead to more efficient use of power grid infrastructure and resources.[7]
>
> Three-part rates will incentivize customers to smooth their energy consumption profile even if they are not equipped with enabling technologies. More than 40 pilot studies and full-scale rate deployments involving over 200 rate offerings over roughly the past dozen years have found that customers respond to new price signals by changing their energy consumption pattern. Further, there is some evidence that customers respond not just to changes in the rate structure generally, but specifically to demand charges.[8]

Q. Does the Company currently have the ability to meter demand for all non-DG customers?

A. No, but we expect to have demand meters installed for all residential and SGS customers by the end of 2016.

Q. Earlier you mentioned that the Company supports a plan to move all residential and SGS customers to three-part rates if these rates are "properly designed." Please elaborate.

A. Each component of a three-part rate must be cost-based and accurately reflect the expenses and investments associated with providing electric service to a customer.

- The monthly basic service charge should recover a certain level of fixed costs, such as the meter, service lines, customer service and billing functions, and minimum distribution system costs.
- The demand charge must reflect the cost of meeting a customer's peak electricity load over a specified period of time. Ideally, the demand charge would allow the utility to recover the related generation, distribution and transmission costs and investments necessary to satisfy a customer's demand on the system.

[7] Faruqui, page 13 lines 21-27.
[8] Faruqui, page 14, lines 13-22.

- Finally, the volumetric energy component should be a pass-through of the utility's actual fuel and purchased power costs. Staff's proposed volumetric energy charge also includes a certain level of non-fuel revenue recovery.

Q. Does the Company agree with Staff's proposed basic service charge, demand charge and energy charge?

A. Staff's proposal to increase the residential basic service charge to $15 per month is a step in the right direction. It is important to note that our proposed $20 basic service charge is still far below the average cost to provide service to a residential customer. However, the Company is willing to accept Staff's proposed basic service charge if the Commission adopts an acceptable three-part rate structure for all customers. The Company reserves the right to maintain its original recommendation of $20 in the event the Commission approves the continuation of two-part rates.

We are generally in agreement with Staff's proposed demand and energy charges, with a few modifications that are described in the Rebuttal Testimonies of Dallas Dukes and Craig Jones.

Q. Is the Company recommending any safeguards to protect customers from unusually high bills once they are transitioned to demand-based rates?

A. Yes. During the transition period, the Company will put safeguards in place to promote a smooth transition and minimize any unintended consequences. Four important safeguards include (i) a proposed transition period that will provide the Company with ample time to analyze billing data and adjust rates as necessary to protect vulnerable customers (as discussed by Staff), (ii) a temporary relief valve mechanism to limit demand charge changes for low load factor customers to allow time to adapt to demand-based rates (as discussed in the Rebuttal Testimony of Company witness Dallas Dukes),

(iii) the measurement of customer demand over a one-hour period and (iv) making those measurements during the Company's peak usage periods. As our customers become accustomed to demand-based rates, we expect to phase out these safeguards as part of UNS Electric's next rate case. The Rebuttal Testimonies of Dallas Dukes and Craig Jones address this in more detail.

Q. Please describe the Company's plans to help customers understand three-part rates.

A. We take very seriously our duty and obligation to make sure our customers receive open and honest communication about their electric rates. The Company is developing a comprehensive customer outreach and education plan that will include many of the elements proposed by Staff, including:

- **Usage data.** We will provide customers with demand data for at least three months prior to implementing three-part rates. Such data will also be made available on an ongoing basis.[9]
- **Phase-in.** The Company believes the transition to new rates could begin as soon as the first quarter of 2017. While Staff suggests that the transition could be completed in phases[10], the Company is proposing to migrate all customers at the same time. In addition, we are recommending that the transition occur in February or March 2017.
- **Unintended consequences.** We support Staff's recommendation that the rate design portion of the case remain open for at least 18 months to monitor the transition and address problems as they occur.[11]

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[9] Direct Rate Design Testimony of Howard Solganick ("Solganick Rate"), page 13 lines 17-20, page 30 lines 17-26.
[10] Solganick Rate, page 13 lines 22-26, page 14 lines 103.
[11] Solganick Rate, page 14 lines 5-10.

- **Vulnerable customers.** We support Staff's position on vulnerable customers. Potentially vulnerable customers should self-identify; however, existing DG customers do not comprise a vulnerable group.[12]

Despite TASC's claim that the Company would not educate customers about three-part rates[13], we already are preparing a comprehensive plan to educate customers about all important rate and rate design changes that are approved by the Commission at the conclusion of this proceeding. We would also work closely with Commission Staff and other stakeholders in developing and implementing this plan. In my Direct Testimony in TEP's rate case, I stated the following:

> Equally important as getting the rate design right is promoting customer awareness. If mandatory three-part rates are applied to all residential customers, we, along with Commission Staff and other stakeholder groups, would need to conduct outreach to educate our customers about three-part rates. Any customer awareness efforts should include a phase-in or transitional period in order to provide for a smoother implementation of demand-based rates. A phase-in period should also include the ability to make revenue-neutral rate design changes to avoid unintended consequences.[14]

Needless to say, we hold an identical view for UNS Electric. Moreover, I strongly disagree with the intervenors who suggest that our customers will be unable to understand three part rates. Company witness Dallas Dukes discusses the guidelines of our transition plan in his Rebuttal Testimony.

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[12] Broderick, page 9, lines 14-23, page 10 lines 1-8.
[13] Direct Rate Design and Cost of Service Testimony of Mark Fulmer ("Fulmer"), Page 23, lines 1-7.
[14] Direct Testimony of David G. Hutchens in Docket No. E-01933A-15-0322 (filed November 5, 2015), page 19, lines 18-24).

Q. Does the Company support Staff's position that existing DG customers be transitioned to three-part rates?

A. Yes. Although the Company originally sought to exempt most existing DG customers from mandatory use of three-part rates, we recognize that doing so would preserve inaccurate price signals and lock in a cost-shift that increases rates for other customers. Approved changes in base rates and rate design are typically applied to all customers, including those with DG systems.

IV. RESPONSE TO RUCO'S TESTIMONY.

Q. Have you reviewed RUCO's rate design testimony?

A. Yes.

Q. Do you have any general comments on RUCO's testimony?

A. Yes. The Company opposes RUCO's recommendations to (i) keep the third tier in the Company's existing two-part residential rates and (ii) increase the residential basic service charge to just $12.26[15], which is far below the Company's and Staff's proposals. If the Commission decides to continue offering two-part volumetric rates to customers, it is critical that we address the Company's ability to recover its non-fuel revenues. As I stated in my Direct Testimony:

> …the "new normal" of flat or declining sales - resulting primarily from DG and EE - limits the Company's opportunity to recover its cost through rates that feature an inclining block structure. This problem is exacerbated by DG customers whose energy usage rarely reaches the upper tiers, thus shift fixed costs to other customers who use more energy. UNS Electric is proposing to eliminate certain upper tiers to reduce this cost shift and enhance the Company's ability to recover its fixed costs.[16]

[15] Huber, Exhibit 2 page 1.
[16] Hutchens, page 13 lines 1-7.

The Company's billing data provides perspective regarding the ongoing decline in residential use per customer. During 2014 (the test year used in this case), the Company issued more than 23,000 bills that reflected zero electric use.[17,18] This represents a 144% increase over zero-consumption bills issued during the previous test year (12 months ended June 30, 2012). Also during 2014, the Company issued over 14,000 bills to net metering customers, of which 57% reflect zero electric use.

We also oppose RUCO's recommendations regarding net metering and three-part rates. Please refer to the testimonies of Dallas Dukes, Carmine Tilghman and Craig Jones for more information.

V. <u>THE COMPANY'S NET METERING TARIFF SHOULD BE APPROVED IN THIS RATE CASE.</u>

Q. Briefly summarize the Company's proposed net metering tariff

A. Under UNS Electric's proposed Net Metering Tariff, new users of DG systems (i) would not be allowed to "bank" or carry-forward excess kilowatt-hours ("kWh") to offset future electricity consumption and (ii) would be compensated for excess energy at the Renewable Credit Rate.[19]

Q. Is the Company willing to consider other net metering proposals or alternative methodologies of valuing excess generation produced by DG customers?

A. Certainly. However, with the exception of RUCO, none of the other parties in this proceeding provided any new net metering proposals or alternatives in their testimony.

[17] Schedule H-5, page 1 (filed May 4, 2015 with the Company's rate application).
[18] Of the 23,000 bills, over 8,000, or 35%, were issued to net metering customers.
[19] Equivalent to the most recent utility-scale renewable purchased power agreement connected to the distribution system of Tucson Electric Power.

Q. Is the current rate case proceeding the proper venue to approve a new net metering tariff?

A. Yes, without question. I would like to point out that UNS Electric and its sister company, TEP, filed applications in March 2015 to update their net metering tariffs.[20] Although both UNS Electric and TEP believe that the Commission can approve a net metering tariff outside of a rate case, several parties who are intervenors in this rate case, including TASC,[21] Vote Solar,[22] the Arizona Solar Deployment Alliance[23] and the Arizona Solar Energy Industry Association,[24] argued that a net metering tariff must be approved in a rate case.[25] Yet these parties have yet to offer any new net metering proposals in this docket.

While we understand Staff's desire to wait for the outcome of the Commission's investigation of the value and cost of DG (Docket No. E-00000J-14-0023),[26] this proceeding is the proper venue for approval of a new net metering tariff for UNS Electric. It is unclear when the value and cost of DG proceeding will conclude and what result it will ultimately produce. On the other hand, this rate proceeding will provide sufficient Company specific data and evidence to support the Commission's approval, modification or rejection of UNS Electric's proposed net metering tariff.

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[20] March 25, 2015, Docket No. E-04204A-15-0099 (UNS Electric) and Docket No. E-01933A-15-0100 (TEP).

[21] TASC brief (May 15, 2015, Docket No. E-01933A-15-0100), page 1 lines 23-24, page 4 lines 5-6.

[22] Vote Solar brief (May 15, 2015, Docket No. E-01933A-15-0100), page 1 lines 23-24, page 2 line 1, and lines 11-24.

[23] Arizona Solar Deployment Alliance brief (May 15, 2015, Docket No. E-01933A-15-0100) page 1 line 16.

[24] Arizona Solar Energy Industry Association brief (May 18, 2015, Docket No. E-01933A-15-0100) page 2 line 9.

[25] In light of the procedural posture in that docket, in June 2015, TEP withdrew its net metering application and accelerated the filing of its rate case (Notice of Withdrawal of Application filed June 19, 2015, Docket No. E-01933A-15-0100).

[26] Broderick, Executive Summary; Solganick Rate, page 45 lines 16-25.

Q. How would you respond to accusations that UNS Electric's proposed net metering tariff will "kill" solar in the Company's service territory?

A. Despite the doom and gloom predictions by TASC,[27] Vote Solar[28] and AURA,[29] DG installations have continued to increase in UNS Electric's service territory since the Company announced it would request changes to its net metering tariff. As described in the Direct Testimony of Dallas Dukes, new DG customers would still realize significant savings under the Company's proposed three-part rate structure and net metering tariff.

Q. Would you like to make any further comments on the third-part solar DG market?

A. Yes. In December 2015, Congress extended the solar investment tax credit to the end of 2021 thus preserving significant subsidies for the third-party solar DG market. The following are excerpts from a Wall Street Journal article from December 16, 2015.[30]

> U.S. home solar adoption has soared in recent years, thanks to heavy government underwriting and falling prices for solar equipment. So far this year nearly 1,500 megawatts of solar panels have been installed on 214,000 homes across the country, according to the Solar Energy Industries Association and GTM Research.
>
> Extending the tax credits would likely boost the amount of solar panels installed over the next five years by more than half, to 72,000 megawatts, GTM analysts predicted. That is enough power to serve nearly 12 million homes, according to SEIA.
>
> The nonpartisan Joint Committee on Taxation estimates that extending tax credits for wind power will cost taxpayers $14.5 billion, while continued solar tax credits will cost $9.3 billion.

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[27] Fulmer, page 17 lines 10-11.
[28] Direct Testimony of Briana Kobor ("Kobor"), page 5 lines 21-22.
[29] Rate Design Testimony of Thomas Alston ("Alston"), page 5 lines 2-3.
[30] http://www.wsj.com/articles/wind-solar-companies-get-boost-from-tax-credit-extension-1450311501

VI. THE COMPANY IS STIPULATING TO CERTAIN ELEMENTS OF STAFF'S PROPOSED NON-FUEL REVENUE INCREASE.

Q. Is the Company willing to stipulate to Staff's proposed non-fuel revenue increase?

A. Yes. The Company will stipulate to an $18.5 million increase to adjusted test-year non-fuel revenues, which reflects Staff's recommendation of an $18.1 million[31] base rate increase with some minor adjustments that are described in the Rebuttal Testimony of David Lewis. The primary difference between the Company's proposed non-fuel revenue increase of $22.6 million and Staff's recommended $18.1 million increase relates to return on equity and the return on the fair value increment. The Rebuttal Testimonies of Ann Bulkley and Kentton Grant provide further explanation regarding these differences.

VII. ECONOMIC DEVELOPMENT RATE.

Q. Briefly describe the Company's proposed Economic Development Rate ("EDR").

A. As a way to help promote economic development in the Company's service territories, UNS Electric proposed to offer discounted rates to new or existing large business customers that meet certain requirements, including a minimum load factor.

Q. Would you like to make any clarifying remarks about the Company's proposed EDR?

A. Yes. The testimonies of Staff,[32] RUCO,[33] NUCOR,[34] Walmart[35] and AIC[36] generally recognize the merits of UNS Electric's EDR; however, some of these parties express

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[31] Staff's revenue requirement testimony, Direct Testimony of Donna Mullinax, page 8 line 12.
[32] Solganick Rate, page 52 lines 5-7.
[33] Huber, page 8, lines 20-23, page 9 lines 1-6.
[34] Direct Testimony of Dr. Jay Zarnikau page 30, lines 15-18.
[35] Testimony of Gregory W. Tillman, page 9 lines 8-19.

concerns about costs being shifted from EDR customers to other customer classes. I would like to emphasize that the any lost non-fuel revenues resulting from discounts provided to customers through the EDR will be borne by the Company. UNS Electric will not seek recovery of any lost non-fuel revenues associated with the EDR in future rate case proceedings. The long-term benefits of attracting or retaining large, high load factor customers greatly outweigh the short-term costs. The Rebuttal Testimony of Dallas Dukes provides further information regarding the Company's EDR proposal.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

[36] Direct Testimony of GaryYaquinto, pages 8-9, lines 1-22.

BEFORE THE ARIZONA CORPORATION COMMISSION

<u>COMMISSIONERS</u>
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

EXHIBIT
UNSE-5
ADMITTED

Rejoinder Testimony of

David G. Hutchens

on Behalf of

UNS Electric, Inc.

February 29, 2016

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is David G. Hutchens and my business address is 88 East Broadway Blvd., Tucson, Arizona, 85701.

Q. Did you file Direct or Rebuttal Testimony in this proceeding?

A. Yes. I filed both.

Q. What is the purpose of your Rejoinder Testimony in this proceeding?

A. The purpose of my testimony is to generally comment on the Surrebuttal Testimonies filed in this proceeding. A number of the parties put forth positions that do not take into consideration the overall public interest that the Commission must consider in deciding the issues in this case.

Q. How do you believe that the Commission can best ensure that the public interest is served in this proceeding?

A. The public interest can best be served through rates that support the availability of safe, reliable and affordable electric service. To achieve these objectives, UNS Electric has focused on efficient operations while seeking to secure only the most cost-effective energy resources to serve customers' energy needs. The Company also must effectively manage the growth of demand during peak usage periods to limit the costs that must be passed along to customers. The rates proposed in this proceeding, including the three-part rates developed for residential customers, are designed from the ground up to support these efforts. For this reason and many others, the approval of the Company's proposal would serve the public interest.

Q. How would the public interest be served by the use of three-part rates for residential customers?

A. Utility rate design should serve the public interest. Customers rightly expect, that their utilities and the regulators who oversee them have provided them with a fair price – one that reflects their appropriate share of the costs that underlie their service.

In other words, our customers are trusting us to get rate design right. And as testimony in this case has made clear, the continued use of two-part rates with a low fixed charge would not reflect the best interest of customers or the utility's ability to recover the costs of providing safe, reliable service.

Residential customers' total consumption is no longer a fair proxy for the cost that utilities like UNS Electric must incur to serve them. There was a time when it was close enough, but that was before rooftop solar arrays, robust energy efficiency measures, and other new technologies reshaped the landscape for residential electric service.

We have always known that utility service costs are driven in large part by demand. This is particularly true in Arizona, where our infrastructure must have the capacity to provide reliable service on the hottest days of the year (even if those days happen to be cloudy).

Customers should be billed based on rates that reflect the cost of service. They should be told what really affects their bills, even if some parties to this case claim they won't be able to understand it. The overall public interest should be put ahead of special interests that seek to bend rate design to their own purposes.

Q. Would customers have difficulty understanding three-part rates?

A. Three-part rates are no more confusing for customers than our current rates, which include multiple tiers, charges that change with the seasons and an alphabet soup of acronyms. I'm also confident that customers will find them less confusing once parties in this matter stop spreading misleading statements about them. I've seen our proposed demand charge described as a fine or extra charge designed to penalize our customers. Such misleading statements cloud the understanding of a concept – electric demand – that clearly plays a critical role in determining the costs of providing electric service.

Energy demand is not overly difficult to understand, particularly in the context of other charges on customers' bills. The Company is committed to a comprehensive communications campaign that will educate customers about our new rates and provide information for managing their electric demand. It will be far easier to manage peak hourly energy use under our proposed rates than it has been for customers to determine when their monthly consumption reaches a level subject to higher per-kWh charges under a traditional tiered rate structure.

Customers who choose to do so will find it easy enough to understand our proposed rates. Our focus, though, should be on approving fair and accurate rates that recover costs appropriately from all customers.

Q. Would three-part rates increase costs for UNS Electric customers?

A. No. In the short term, the proposed rates are designed to be revenue neutral for UNS Electric. Over the long term, though, three-part rates would likely lead to *lower* costs for our customers. By providing more accurate price signals regarding the true cost of demand, three-part rates would give residential customers a good reason to reduce their peak hourly energy use during high usage periods. This, in turn, would reduce UNS Electric's need for system investments far more effectively than reductions in kWh consumption, which are the only savings incentivized under current two-part rates. Reducing the Company's need for system investments ultimately would lead to lower rates for our customers, a clear benefit to the public interest.

Q. How would three-part rates affect UNS Electric's service reliability?

A. Residential rates with a demand component would provide customers with a clear incentive to use less energy during periods of peak electric demand. If they respond to these accurate price signals, their reduced usage would relieve pressure on transformers, conductors and other key system components that can be subject to failure during peak load or overload conditions. In this way, three-part rates would contribute positively to the reliability of the Company's service, providing another reason why their approval would serve the public interest.

Q. Some providers of distributed generation (DG) solar power systems claim three-part rates would discourage the use of renewable energy resources in UNS Electric's service territory. Is that true?

A. Not at all. By reducing embedded subsidies for DG systems, our proposed rates and net metering revisions would redirect investment to more cost-effective community-scale systems that provide greater benefits shared by all customers. Rooftop systems would remain an affordable option for customers committed to providing a portion of their own energy from the sun. In fact, our proposed rates would give customers a chance to reduce their impact on both the environment *and* their neighbors' utility bills. While this might not serve the business interests of some Intervenors in this matter, it most definitely would serve the public interest.

Q. How might the Company's proposed rates affect the local economy in UNS Electric's service territory?

A. Keeping our rates as affordable as possible is the best contribution we can make to our local economy. Our proposal would accomplish that objective in part by reducing the subsidies embedded in our current rates that lead to higher costs for customers. Traditional two-part rates with a low fixed-cost component charge too high a price for energy while ignoring the cost of demand – the factor that more directly drives the need for system improvements and higher rates. This, in turn, has created unduly generous incentives for DG solar systems and other strategies that reduce kWh consumption without meaningful, reliable reductions in peak usage. Sending more accurate price signals will result in more effective energy management strategies that reduce, rather than increase, costs for customers.

Some Intervenors in this proceeding have adopted a more self-interested economic development strategy that calls for the preservation of current subsidies for solar DG systems. While their singular focus is understandable, given their business model, the economic development efforts of entire communities should not be compromised by electric rates held artificially high to promote a single industry. Like any regulated utility, UNS Electric's success is determined by the economic well-being of the communities it serves. That's why our proposal – including our proposed economic development rate – are designed to provide broad benefits to all customers and, as such, would serve the public interest.

Q. Why has your Rejoinder Testimony focused so intently on the public interest?

A. I want to make sure we don't lose sight of our obligations to customers in this increasingly crowded and contentious docket. Many of the parties who have intervened in this matter have no real interest in the bills our customers pay. Rather, they hope to use this proceeding as a proxy for an industry debate that has filled the pages of trade journals, driven up consulting fees and influenced stock prices. We must remain focused on the true purpose of this proceeding: approving rates that fairly reflect our prudently incurred costs and provide solid support for our continued efforts to provide safe, reliable and affordable service to customers. That remains our first and only priority and the best way to ensure that the public interest is served.

Q. Do you have any additional comments?

A. No.

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 FOR RELATED APPROVALS.	DOCKET NO. E-04204A-15-______

Direct Testimony of

Terry Nay

on Behalf of

UNS Electric, Inc.

May 5, 2015

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Terry Nay. My business address is 88 East Broadway Blvd., Tucson, Arizona 85701.

Q. What is your position with UNS Electric, Inc. ("UNS Electric" or the "Company")?

A. I am the Senior Director of UNS Electric and Corporate Safety. As the Sr. Director of UNS Electric I provide operational and budgetary oversight for the three districts that comprise UNS Electric: the Santa Cruz District, Kingman District and the Lake Havasu City District.

Q. Please describe your education and experience.

A. I graduated from Brigham Young University with a B. S. in Environmental and Occupational Safety and Health. I graduated from the University of Arizona with a Masters of Business Administration.

I was hired in 2008 as the Corporate Safety Director. Since that time I have served as the Director of Operational Excellence and Corporate safety, and in my current role.

Q. What is the purpose of your Direct Testimony?

A. I provide an overview of UNS Electric's operations. The topics I cover include the Company's: (i) service territory; (ii) customer base; (iii) generation assets and power supply contracts; (iv) safety and reliability performance; (v) ongoing efforts to improve the transmission and distribution system; (vi) actual and forecasted capital investments; and (vii) an overview of efforts to appropriately control Operations and Maintenance ("O&M") expense.

II. UNS ELECTRIC OPERATIONS.

Q. Please describe UNS Electric's service territory, customer base and sales mix.

A. UNS Electric provides electric service to the majority of Mohave County and Santa Cruz County, including the cities of Kingman, Lake Havasu City and Nogales. The Company serves over 74,000 customers in Mohave County and over 19,000 customers in Santa Cruz County. Approximately 88% of UNS Electric customers are residential, 11% are commercial and less than 1% are industrial/mining.

Q. Please provide more detail about UNS Electric's generation assets.

A. UNS Electric's generating assets are described below.

- Gila River Unit 3 ("Gila River") is a 550 MW natural gas-fired combined cycle generating facility located near Gila Bend, Arizona. The Company owns 25% of the capacity of Gila River, or approximately 138 MW. Gila River is expected to provide approximately 40% of UNS Electric's base load requirements to serve retail customers.
- Black Mountain Generating Station ("BMGS") is located in Kingman, Arizona and provides UNS Electric with 90 MW of natural gas-fired combustion turbine capacity. BMGS is used primarily as a peaking station, and is therefore operated during periods of high demand in Mohave County.
- Valencia Power Plant ("Valencia") is located in Nogales, Arizona. Valencia consists of four natural gas and diesel-fueled combustion turbine units that provide approximately 63 MW of resource capacity. The facility is directly interconnected with the distribution system serving the city of Nogales and the surrounding areas. The Valencia turbines are used primarily as a back-up supply if the 138 kV transmission line trips or is taken out of service for maintenance.

- UNS Electric owns two solar facilities with a total 8 MW of solar photovoltaic capacity. In Santa Cruz County, UNS Electric owns the 7 MW Rio Rico facility, and in Mohave County, the Company owns the 1 MW La Senita facility.

Q. Please describe the Company's commitment to providing safe and reliable service.

A. Providing safe, reliable and economic electric service is the principal focus of UNS Electric's business. As I discussed above, UNS Electric is developing diverse resources to meet the load in its service area. And as set forth below, the Company is continuing its efforts to upgrade the quality of service it provides. As a result, UNS Electric has provided and will continue to provide safe and reliable service to its customers.

Q. Would you provide an overview of UNS Electric's operations from a safety and reliability standpoint?

A. Safety is an essential part of UNS Electric's operational philosophy. We strive to perform all of our work in a manner that prevents injury to ourselves, our co-workers, our customers and the communities we serve.

This philosophy is supported by our overall "Target Zero" safety strategy, which includes three elements:

1) active safety leadership;
2) increased employee involvement and engagement in safety activities; and
3) hazard control and regulatory compliance.

The focused implementation of this strategy throughout the Company has resulted in a significant improvement in our total recordable incident rate, which fell from 4.85 in 2013 to 2.72 in 2014.

UNS Electric is committed to effective and efficient operations and providing top tier reliability without compromising on safety. The Company's system reliability compares favorably on two common industry benchmarks: System Average Interruption Duration Index ("SAIDI") and Customer Average Interruption Duration Index ("CAIDI"). These comparisons can be made annually based on the Edison Electric Institute ("EEI") Distribution Reliability Survey, which aggregates data from utilities across the country. EEI survey data is formatted into first, second, third, and fourth quartiles to indicate how individual utilities compare to their peers. UNS Electric's performance earned the Company a spot in EEI's first or second quartile each year from 2012 to 2014. The reliability of UNS Electric's distribution operations provides customers with significant benefits, including safety, productivity, comfort and convenience.

Q. O&M costs incurred by UNS Electric in the test year reasonable?

A. Yes. Our corporate goals include maintaining O&M at or below a predetermined level. Additionally, our use of continuous improvement processes and techniques help us to improve operational efficiencies while reducing costs. As a result of these continuous improvement activities our 2014 O&M expenses were only 1.2% above 2012 expenses despite increases in wages, benefits, bad debt, transportation and communication costs. We also actively monitor all O&M expenses monthly. Area managers are required to report on variances from the plan and are responsible for identifying and acting on opportunities to be more efficient while ensuring the continued safety of our employees and the community, and the continued reliability of the electrical system supplying electric service to our customers.

Q. Please describe UNS Electric's ongoing efforts to upgrade its transmission system.

A. In 2013, the Company upgraded the transmission line that serves customers in Santa Cruz County by increasing the line's capacity to 138 kilovolts (kV) from 115 kilovolts. In addition to the voltage upgrade, UNS Electric also interconnected the northern end of the transmission line with a major import substation (the Vail Substation) and replaced aging wooden H-frame structures with durable steel monopoles. This project enhanced the Company's ability to meet demand in Santa Cruz County while improving the reliability of service for customers there.

UNS Electric also has an ongoing transmission system improvement program to upgrade and strengthen the 69kV transmission system in Mohave County. Significant portions of the 69kV system were built between 1930 and 1970. The improvement plan will enhance reliability and properly balance demand. Some of the key upgrades to Mohave County's 69kV system from 2012 to 2014 include:

1) The addition of a 230kV-to-69kV transformer (T2) at the Griffith Substation;
2) Rebuilding and reconductoring six miles of the Hoover 69 kV line from Chloride to Mineral Park substations.
3) Rebuilding and reconductoring the 69 kV line between Coyote Breaker and North Kingman substations, which will support the future relocation of the North Kingman Substation and will allow for contingency switching.
4) Rebuilding and reconductoring of the 69 kV line between the Beverly and Stockton Hill Road to support the future relocation of the North Kingman Substation and to allow for contingency switching; and
5) Improvements to the Boriana Substation, where new breakers, electronic relays and fiber communication equipment was installed.

These projects are part of a systematic upgrade of the 69kV transmission system in the Mohave service territory to improve the reliability of service in the area.

Q. How does UNS Electric assess the need for near-term improvements to its distribution systems?

A. UNS Electric uses a three prong approach to assess the need for near-term improvements to the distribution system:

1) Critical Circuit Analysis – UNS Electric engineers, with assistance from Tucson Electric Power Company engineers, evaluate each circuit in the system based on reliability, demand, capacity and type of load. This data is used to create a Critical Circuit rating, which is used to prioritize work on these circuits. This analysis helps us identify and focus our resources on those circuits with the greatest need. It also provides insight, although it is not the sole determining factor, into which circuits need to be patrolled by journeyman linemen.

2) Circuit Patrols – UNS Electric journeyman linemen perform detailed land-based patrols of circuits that have experienced recurring outages. The purpose of these patrols is to identify maintenance issues associated with insulators, guy wires, poles, cross arms, ground wire attachments, static and neutral wires, conductors and other distribution equipment and to evaluate the threat posed by nearby vegetation. The linemen also evaluate the line for opportunities to implement circuit improvements that would decrease outage severity. Any issues identified on these patrols or inspections are prioritized based on severity and addressed as needed.

3) Annual Helicopter Patrols – Long rural radial distribution lines and system transmission lines are inspected by journeymen lineman via helicopter patrols. These patrols allow UNS Electric to inspect circuits that are difficult to access either due to terrain or distance. The same criteria and methodology that was outlined above for the Circuit patrols are applied during these helicopter patrols.

UNS Electric's application of this three-prong approach is designed to increase system reliability and safety.

Q. In Condition 28 of the Fortis/UNS Energy Merger settlement agreement, the Regulated Utilities, including UNS Electric, agreed to use their best efforts to maintain or improve their quality of service based upon SAIDI, System Average

Interruption Frequency Index ("SAIFI"), and CAIDI. Please discuss UNS Electric's efforts in this area and the results.

A. Condition 28 required UNS Electric to use it best efforts to "maintain a rolling 3-year average [SAIDI], [SAIFI], and [CAIDI] at a maximum of the 3-year averages for each of those measures for the period 2011 through 2013 as reported to the Commission in Docket Nos. E-00000A-11-01113 and E-00000V-13-0070." Currently, UNS Electric is performing better than the 3-year averages.

UNS Electric continues to focus on improving the reliability of the transmission and distribution systems that service Mohave and Santa Cruz counties. In addition to the three-prong approach that is described above, we have installed and implemented the use of an Outage Management System ("OMS") in the System Control Office. The OMS provides real-time predictions of outage causation based on customer reports and information from the Energy Management System ("EMS"). This enhances the field response personnel's ability to identify and resolve outages more quickly. By using the OMS system to capture and report outage causation, we can more effectively identify recurring causes and address them, thus preventing future outages and increasing system reliability.

Q. In its most recent rate case, UNS Electric agreed to comply with certain Staff recommendations regarding operational reliability. Has UNS Electric met those recommendations?

A. Yes, it has. Attachment F to the Settlement Agreement approved by Decision No. 74235 (December 31, 2013) set forth four recommendations.

In compliance with the first recommendation, UNS Electric's distribution quality of service indices are available on both a monthly and calendar year basis. As requested in the second recommendation, UNS Electric submitted those indices for the calendar year 2013 for Staff review.

In compliance with the third recommendation, UNS Electric has prepared an annual listing of the worst-performing circuits and has adopted a target circuit maintenance program, which is discussed above.

Finally, in compliance with the fourth recommendation, UNS Electric continues to include thermal scanning of the substation switchyard bus and connected lines on a regular basis, including BMGS.

Q. Has UNS Electric maintained its community service activities?

A. Yes. Our commitment to the communities we serve is stronger than ever. UNS Electric's employees joined their friends and family members in donating more than 3,500 volunteer hours to 44 different nonprofit and other charitable organizations that provide services within the Company's service territories. Our Company shareholders bolstered these efforts by contributing more than $61,000 to nonprofit groups in communities served by UNS Electric. With support from our Community Action Team, our employees have held leadership positions on 7 nonprofit boards of directors.

III. CAPITAL INVESTMENTS.

Q. Please provide details regarding UNS Electric's capital investment since the last test year (which ended June 30, 2012).

A. The following table outlines investments in capital projects from July 2012 through December 31, 2014.

($ Millions)	2012*	2013	2014	Total Capital Investments
Capital Expenditures	$22	$56	$93	$171

*July 1, 2012 – December 31, 2012

UNS Electric's cumulative capital investments during the past 2.5 years totaled $171 million. This total includes: $55 million for the purchase of Gila River; $75 million for transmission and distribution system improvements; $8 million to accommodate new customer demands; and $17 million for solar photovoltaic projects.

UNS Electric's system improvements include the previously mentioned transmission line upgraded in Santa Cruz County, 69 kV transmission system improvements in Mohave County, the installation of a second transformer at the Griffith Substation, and replacement and betterment initiatives in our distribution systems in both Mohave County and Santa Cruz County.

Q. Please describe UNS Electric's plans for future capital expenditures.

A. The following table outlines the estimated capital expenditures for 2015-2019.

($ Millions)	2015	2016	2017	2018	2019	Total Capital Investments
Capital Expenditures	$38	$37	$39	$38	$37	$189

The Company's capital expenditures over the next five years are expected to average approximately $38 million per year. This total includes: $14 million for generation system improvements; $91.4 million for transmission and distribution system improvements, $26.1 million for new customer demands; and $27.5 million for solar or renewable energy projects.

Q. Does this conclude your Direct Testimony?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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

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 REQUEST FOR APPROVAL OF RELATED FINANCING.	DOCKET NO. E–04204A–15–

Direct Testimony of
Dr. Ronald E. White
on Behalf of
UNS Electric, Inc.

May 5, 2015

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BEFORE THE
ARIZONA CORPORATION COMMISSION

PREPARED DIRECT TESTIMONY OF
DR. RONALD E. WHITE
IN DOCKET NO. E–04204A–15–___

Q. **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Ronald E. White. My business address is 17595 S. Tamiami Trail, Suite 260, Fort Myers, Florida 33908.

Q. **WHAT IS YOUR OCCUPATION?**

A. I am President of Foster Associates Consultants, LLC.

I. QUALIFICATIONS

Q. **WOULD YOU BRIEFLY DESCRIBE YOUR EDUCATIONAL TRAINING AND PROFESSIONAL BACKGROUND?**

A. I received a B.S. degree in Engineering Operations and an M.S. degree and Ph.D. (1977) in Engineering Valuation from Iowa State University. I have taught graduate and undergraduate courses in industrial engineering, engineering economics, and engineering valuation at Iowa State University and previously served on the faculty for Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University. I also conduct courses in depreciation and public utility economics for clients of the firm.

I have prepared and presented a number of papers to professional organizations, committees, and conferences and have published several articles on matters relating to depreciation, valuation and economics. I am a past member of the Board of Directors of the Iowa State Regulatory Conference and an affiliate member of the joint American Gas Association (A.G.A.) – Edison Electric Institute (EEI) Depreciation Accounting Committee, where I previously served as chairman of a standing committee on capital recovery and its effect on corporate economics. I am also a member of the American Economic Association, the Financial Management Association, the

Midwest Finance Association, and a founding member of the Society of Depreciation Professionals.

Q. **WHAT IS YOUR PROFESSIONAL EXPERIENCE?**

A. I joined the firm of Foster Associates in 1979, as a specialist in depreciation, the economics of capital investment decisions, and cost of capital studies for ratemaking applications. Before joining Foster Associates, I was employed by Northern States Power Company (1968–1979) in various assignments related to finance and treasury activities. As Manager of the Corporate Economics Department, I was responsible for book depreciation studies, studies involving staff assistance from the Corporate Economics Department in evaluating the economics of capital investment decisions, and the development and execution of innovative forms of project financing. As Assistant Treasurer at Northern States, I was responsible for bank relations, cash requirements planning, and short–term borrowings and investments.

Q. **HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY BODY?**

A. Yes. I have testified in numerous proceedings before administrative and judicial bodies in over thirty jurisdictions, including Arizona. I have also testified before the Federal Energy Regulatory Commission, the Federal Power Commission, the Alberta Energy Board, the Ontario Energy Board, and the Securities and Exchange Commission. I have sponsored position statements before the Federal Communication Commission and numerous local franchising authorities in matters relating to the regulation of telephone and cable television. A more detailed description of my professional qualifications is contained in Attachment REW–1.

II. PURPOSE OF TESTIMONY

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

A. Foster Associates was engaged by UNS Electric, Inc. (UNS Electric or UNSE), an operating subsidiary of UniSource Energy Services, Inc., to conduct a 2014 depreciation rate study for plant subject to the jurisdiction of the Arizona Corporation Commission (ACC). The purpose of my testimony is to sponsor and describe the study conducted by Foster Associates.

At the request of UNSE, the 2014 study includes the development of 2015 depreciation rates for Gila River Power Station Unit 3. In December 2014, UNSE purchased a 25 percent interest in Unit 3 from Entegra Power Group, LLC. The remaining 75 percent interest was purchased by TEP, an affiliate of UNSE. Gila River Unit 3 is a gas–fired combined cycle unit with a nominal capacity rating of 550 MW. The scope, findings and recommendations of the 2014 study are contained in Exhibit REW–1.

III. Development of Depreciation Rates

Q. PLEASE EXPLAIN WHY DEPRECIATION STUDIES ARE NEEDED FOR ACCOUNTING AND RATEMAKING PURPOSES.

A. The goal of depreciation accounting is to charge to operations a reasonable estimate of the cost of the service potential of an asset (or group of assets) consumed during an accounting interval. A number of depreciation systems have been developed to achieve this objective, most of which employ time as the apportionment base.

Implementation of a time–based (or age–life) system of depreciation accounting requires the estimation of several parameters or statistics related to a plant account. The average service life of a vintage, for example, is a statistic that will not be known with certainty until all units from the original placement have been retired from service. A vintage average service life, therefore, must be estimated initially and periodically revised as indications of the eventual average service life becomes more certain. Future net salvage rates and projection curves, which describe the expected distribution of retirements over time, are also estimated parameters of a depreciation system that are subject to future revisions. Depreciation studies should be conducted periodically to assess the continuing reasonableness of parameters and accrual rates derived from prior estimates.

The need for periodic depreciation studies is also a derivative of the ratemaking process which establishes prices for utility services based on costs. Absent regulation, deficient or excessive depreciation rates will produce no adverse consequence other than a systematic over or understatement of the accounting measurement of earnings. While a continuance of such practices may not comport with the goals of depreciation accounting, the achievement of capital recovery is not dependent upon either the amount or the timing of depreciation expense for an unregulated firm. In the case of a regulated utility, however, recovery of investor–supplied capital is dependent upon allowed revenues, which are in turn dependent upon approved levels of depreciation expense. Periodic reviews of depreciation rates are, therefore, essential to the achievement of timely capital recovery for a regulated utility.

It is also important to recognize that revenue associated with depreciation is a significant source of internally generated funds used to finance plant replacements and new capacity additions. This is not to suggest that internal cash generation should be substituted for the goals of depreciation accounting. However, the potential for realizing a reduction in the marginal cost of external financing provides an added incentive for conducting periodic depreciation studies and adopting proper depreciation rates.

Q. PLEASE DESCRIBE THE PRINCIPAL STEPS INVOLVED IN CONDUCTING A DEPRECIATION STUDY.

A. The first step in conducting a depreciation study is the collection of plant accounting data needed to conduct a statistical analysis of past retirement experience. Data are also collected to permit an analysis of the relationship between retirements and realized gross salvage and cost of removal. The data collection phase should include a verification of the accuracy of the plant accounting records and a reconciliation of the assembled data to the official plant records of the company.

The next step in a depreciation study is the estimation of service life statistics from an analysis of past retirement experience. The term *life analysis* is used to describe the activities undertaken in this step to obtain a mathematical description of the forces of retirement acting upon a plant category. The mathematical expressions used to describe these forces are known as survival functions or survivor curves.

Life indications obtained from an analysis of past retirement experience are blended with expectations about the future to obtain an appropriate projection life curve. This step, called *life estimation*, is concerned with predicting the expected remaining life of property units still exposed to the forces of retirement. The amount of weight given to the analysis of historical data will depend upon the extent to which past retirement experience is considered descriptive of the future.

An estimate of the net salvage rate applicable to future retirements is most often obtained from an analysis of gross salvage and cost of removal realized in the past. An analysis of past experience (including an examination of trends over time) provides a baseline for estimating future salvage and cost of removal. Consideration, however, should be given to events that may cause deviations from net salvage observed in the past. Among the factors that should be considered are the age of plant retirements, the portion of retirements that will be reused, changes in the method of removing plant, the type of plant to be retired in the future, inflation expectations, the shape of the projection life curve, and economic conditions that may warrant greater or lesser weight to be given to the net salvage observed in the past.

A comprehensive depreciation study will also include an analysis of the adequacy of the recorded depreciation reserve. The purpose of such an analysis is to compare the current balance in the recorded reserve with the balance required to achieve the goals and objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized exactly as predicted. The difference between the required (or theoretical) reserve and the recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to extinguish the reserve imbalance.

Although reserve records are typically maintained by various account classifications, the total reserve for a company is the most important indicator of the adequacy (or inadequacy) of recorded depreciation reserves. Differences between theoretical and recorded reserves will arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. Differences will also arise due to plant accounting activity such as transfers and adjustments requiring an identification of reserves at a different level from that maintained in the accounting system. It is appropriate, therefore, and consistent with group depreciation theory, to periodically redistribute recorded reserves among primary accounts based on the most recent estimate of service lives, retirement dispersion and net salvage rates. A redistribution of the recorded reserve will provide an initial reserve balance for each primary account consistent with the estimates of retirement dispersion selected to describe mortality characteristics of the accounts and establish a baseline against which future comparisons can be made.

Finally, parameters estimated from service life and net salvage studies are integrated into an appropriate formulation of an accrual rate based upon a selected depreciation system. Three elements are needed to describe a depreciation system. The sub–elements most widely used in constructing a depreciation system are shown in Table 1 below.

Methods	Procedures	Techniques
Retirement	Total Company	Whole-Life
Compound-Interest	Broad Group	Remaining-Life
Sinking-Fund	Vintage Group	Probable-Life
Straight-Line	Equal-Life Group	
Declining Balance	Unit Summation	
Sum-of-Years'-Digits	Item	
Expensing		
Unit-of-Production		
Net Revenue		

Table 1. Elements of a Depreciation System

The above elements (*i.e.*, method, procedure and technique) can be visualized as three dimensions of a cube in which each face describes a variety of sub–elements that can be combined to form a system. A depreciation system is formed by selecting a sub–element from each face such that the system contains one method, one procedure and one technique.

IV. 2014 DEPRECIATION RATE STUDY

Q. PLEASE DESCRIBE THE SOURCE OF DEPRECIATION RATES CURRENTLY USED BY UNSE.

A. Depreciation rates currently used by UNS Electric were developed in a 2009 technical update of a full study conducted in 2006.[1] Rates developed in the 2009 update were

[1] Unlike a full depreciation study in which projection curves, projection lives and future net salvage rates are estimated from a statistical analysis of recorded retirements and net salvage realized in the past, a technical update generally retains the parameters currently used by the utility and adjusts depreciation rates for known and measurable changes in the age distributions of surviving plant, deprecia-

approved by the Arizona Corporation Commission (ACC) in Docket No. E–04204A–09–0206 (Decision No. 71914, dated September 30, 2010). Depreciation rates approved in Decision No. 71914 were retained in Docket No. E–04204A–12–0504 (Decision No. 74235, dated December 31, 2013).

With the exception of transportation equipment and proposed amortizable categories, projection lives and projection curves recommended in the 2006 study were derived from parameters estimated in a 1991 study conducted by Citizens Utilities Company (Citizens), the prior owner of assets acquired by UNS Electric in 2003.

Current depreciation rates adopted for Gila River were developed by TEP using rates currently approved for UNSE Account 352.00 (Structures and Improvements); Account 353.00 (Station Equipment); Account 390.00 (Structures and Improvements); Account 392.C0 (Transportation Equipment) and Account 393.00 (Stores Equipment). Current remaining–life rates for Other Production accounts were developed using an estimated service life of 45 years with zero net salvage. A 5–year service life was estimated for Account 303.00 (Control Software).

Q. **DID UNSE PROVIDE FOSTER ASSOCIATES PLANT ACCOUNTING DATA FOR CONDUCTING THE 2014 DEPRECIATION STUDY?**

A. Yes. The database used in conducting the current study was constructed by appending plant and reserve transactions recorded over the period 2009–2013 to the database used in conducting the 2009 update. The accuracy and completeness of the appended transactions was verified by comparisons to FERC Form 1 for activity years 2009–2013. The 2014 study database contains aged plant transactions over the 14–year period 1999–2013.

The database used in conducting the 2009 update was constructed by appending plant and depreciation reserve transactions recorded over the period 2006–2008 to the database used in conducting the 2006 study. The accuracy and completeness of

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tion reserves, and average net salvage rates due to the passage of time. A technical update is intended to align depreciation rates with the accounting year the rates will become effective.

the appended transactions was verified by comparisons to FERC Form 1 for activity years 2006–2008.

The database used in conducting the 2006 study was assembled by Foster Associates from two sources. The first source was electronic files obtained from Citizens Communications Company containing: a) aged transfers and retirements over the period 1999–August 2003; and b) age distributions of surviving plant at December 31, 2002. The second data source was electronic files obtained from UNS Electric containing plant and reserve activity over the period September 2003–December 2005 and age distributions of surviving plant at December 31, 2005.

The transfer of assets to UNSE from Citizens prevented reconciling the assembled database to any public reports of Citizens. The integrity of the database, however, was verified for activity years 2004 and 2005 for data provided by UNSE.

The database used for Gila River Power Station consisted of age distributions and recorded depreciation reserves at December 31, 2014.

Q. DID FOSTER ASSOCIATES CONDUCT STATISTICAL LIFE STUDIES FOR UNSE PLANT AND EQUIPMENT?

A. Yes. As discussed in Exhibit REW–1, all depreciable plant accounts were analyzed using a technique in which first, second and third degree polynomials were fitted to a set of observed retirement ratios. The resulting function was expressed as a survivorship function and numerically integrated to obtain an estimate of the projection life. The smoothed survivorship function was then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data. Service life indications derived from the statistical analyses were blended with informed judgment and expectations about the future to obtain an appropriate projection life curve for each plant category. Plant accounts classified in Other Production were identified by location and treated as life–span categories in the 2014 study.

As noted earlier, the database for UNSE contains plant accounting transactions for activity years 1999–2013. While it is theoretically possible to obtain life indications from an actuarial analysis of a single activity year, retirements during the year must be widely distributed over the beginning–of–year surviving vintages of a nearly mature plant account.[2] A similar limitation applies to the current database of UNSE which now contains only 14 activity years. Retirements must be sufficiently distributed across vintages within these 14 years to obtain meaningful service life indications from a statistical analysis.

Life tables were constructed for each plant account for which retirements were recorded over the period 1999–2013. With few exceptions, life tables constructed over this limited historical period continue to exhibit uniformly high degrees of censoring and indeterminate measurements of service life. These results are again attributable to insufficient retirement experience over the available band of activity years.

Parameters recommended by Foster Associates for accounts in which actuarial analyses failed to produce meaningful service–life indications are those approved for TEP in Docket No. E–01933A–12–0291 (Decision No. 73912, June 27, 2013). Parameters approved for TEP are considered reasonable placeholders for UNSE until sufficient retirement activity produces meaningful service life indications. It can be expected, however, that service life and net salvage statistics for UNSE will gradually converge to those estimated for TEP given that construction standards, maintenance policies and plant accounting practices are common to both TEP and UNSE.

Q. DID FOSTER ASSOCIATES CONDUCT A NET SALVAGE ANALYSIS FOR UNSE PLANT AND EQUIPMENT?

A. Yes. A five–year moving average analysis of the ratio of realized salvage and cost of removal to the associated retirements was used in the 2014 study to: a) estimate realized net salvage rates; b) detect the emergence of historical trends; and c) obtain a basis for estimating future net salvage rates. Cost of removal and salvage opinions obtained from Company personnel were blended with judgment and historical net salvage indications in developing estimates of the future.

[2] Plant maturity is achieved when the age distribution of surviving plant approaches a complete survivor curve descriptive of the forces of retirement acting upon the plant category.

Future net salvage rates for combustion turbine units (*i.e.*, Black Mountain and Valencia) were developed from the projected cost of dismantling these facilities estimated in a 2011 demolition study commissioned by TEP. Terminal net salvage for photovoltaic solar power facilities (*i.e.*, La Senita and Rio Rico) were estimated by UNSE in an asset retirement obligation study. Foster Associates was requested by UNSE to develop terminal net salvage rates for Gila River Unit 3 using dismantlement costs estimated in a 2011 demolition study conducted for the Luna plant owned by TEP.

Q. **DID FOSTER ASSOCIATES CONDUCT AN ANALYSIS OF RECORDED DEPRECIATION RESERVES?**

A. Yes. Statement C provides a comparison of the computed, recorded and redistributed reserves at December 31, 2013. The recorded reserve was $287,769,189 or 44.0 percent of the depreciable plant investment. The corresponding computed reserve is $166,737,609 or 25.5 percent of the depreciable plant investment. A proportionate amount of the measured reserve excess of $121,013,580 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates developed in this study.

The recorded reserve for Gila River was $21,091,164 or 23.9 percent of the depreciable plant investment. The corresponding computed reserve is $21,766,613 or 24.7 percent of the depreciable plant investment. A proportionate amount of the measured reserve shortfall of $645,449 will be amortized over the composite weighted–average remaining life of each rate category.

Q. **IS FOSTER ASSOCIATES RECOMMENDING A REBALANCING OF DEPRECIATION RESERVES?**

A. Yes. It is the opinion of Foster Associates that a redistribution of recorded reserves is appropriate for UNSE at this time. Offsetting reserve imbalances attributable to both the passage of time and parameter adjustments recommended in the current review should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability.

A redistribution of the recorded reserve for depreciable plant was achieved by multiplying the calculated reserve for each primary account within a function or location by the ratio of the total recorded reserves to the calculated total net reserve. The sum of the redistributed reserves is, therefore, equal to the total recorded depreciation reserve before the redistribution.

Depreciation reserves for amortizable categories were redistributed by setting the recorded reserves for amortization accounts equal to the theoretical reserves derived from the recommended amortization periods and distributing the residual imbalances to the remaining depreciable accounts.

Q. **PLEASE DESCRIBE THE DEPRECIATION SYSTEM CURRENTLY USED BY UNSE.**

A. With the exception of amortizable categories, UNS Electric is currently using a depreciation system composed of the straight–line method, broad group procedure, remaining–life technique for all depreciable plant categories. The current system for depreciable categories was approved by the ACC in Docket No. E–1032–92–073 without comment as to the appropriateness of the system or a consideration of alternative systems. The current system was retained in the 2006 study and 2009 update pending estimation of revised parameters in a future depreciation study.

The level of asset grouping identified in the broad group procedure is the total plant in service from all vintages in an account. Each vintage is estimated to have the same average service life. The remaining life of each vintage is estimated from a projection life curve and the attained age of the vintage. The average remaining life for a broad–group plant account or rate category is a direct, dollar–weighted average of the remaining life of each vintage. The weights used in this calculation are the vintage survivors at the beginning of the study year.

The formulation of an account accrual rate using the current system is given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Reserve Ratio} - \text{Future Net Salvage Rate}}{\text{Remaining Life}}.$$

A remaining–life rate is equivalent to the sum of a whole–life rate and an amortization of any reserve imbalance over the estimated remaining life of a rate category. Stated as an equation, a remaining–life accrual rate is equivalent to

$$\text{Accrual Rate} = \frac{1.0 - \text{Average Net Salvage}}{\text{Average Life}} + \frac{\text{Computed Reserve} - \text{Recorded Reserve}}{\text{Remaining Life}}$$

where both the computed reserve and the recorded reserve are expressed as ratios to the plant in service.

Q. IS FOSTER ASSOCIATES RECOMMENDING A CHANGE IN THE DEPRECIATION SYSTEM FOR UNSE?

A. Yes. Depreciation rates recommended in the 2014 study for all depreciable plant categories were derived from a system composed of the straight–line method, vintage group procedure, remaining–life technique. This change in procedure from broad group to vintage group is recommended by Foster Associates to more nearly achieve the goals and objectives of depreciation accounting and to establish consistency with the procedure approved for TEP.

Unlike the broad group procedure in which each vintage is estimated to have the same average service life, consideration is given to the realized life of each vintage when average service lives and remaining lives are derived using the vintage group procedure. The vintage group procedure distinguishes average service lives among vintages and composite life statistics are computed for each plant account. The formulation of an account accrual rate using the straight–line method, vintage group procedure, remaining–life technique is identical to the broad group procedure.

It is the opinion of Foster Associates that the recommended system will remain appropriate for UNSE, provided depreciation studies are conducted periodically and parameters are routinely adjusted to reflect changing operating conditions. It is also the opinion of Foster Associates that amortization accounting currently approved for selected general support asset accounts is consistent with the goals and objectives of depreciation accounting and remains appropriate for these plant categories.

Q. **PLEASE SUMMARIZE THE DEPRECIATION RATES AND ACCRUALS RECOMMENDED FOR UNSE IN THE 2014 STUDY.**

A. Table 2 below provides a summary of the changes in annual depreciation rates and accruals resulting from an application of the depreciation system and parameters recommended for UNSE in the 2014 study.

Function	Accrual Rate			2014 Annualized Accrual		
	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Intangible Plant	4.69%	4.61%	-0.08%	$ 369,214	$ 363,320	$ (5,894)
Other Production	2.99%	2.80%	-0.19%	3,232,974	3,027,404	(205,570)
Transmission	3.54%	1.87%	-1.67%	3,483,939	1,849,081	(1,634,858)
Distribution	3.97%	1.39%	-2.58%	16,020,205	5,609,622	(10,410,583)
General Plant	7.44%	6.10%	-1.34%	2,643,971	2,167,254	(476,717)
Total Utility	3.94%	1.99%	-1.95%	$ 25,750,303	$ 13,016,681	$ (12,733,622)

Table 2. Current and Proposed Rates and Accruals

The composite accrual rate recommended for UNS Electric is 1.99 percent. The current equivalent rate is 3.94 percent. The recommended change in the composite rate is a reduction of 1.95 percentage points.

A continued application of current rates would provide 2014 annualized depreciation expense of $25,750,309 compared with an annualized expense of $13,016,681 using the proposed rates. The resulting 2014 expense reduction of $12,733,622 is largely attributable to adjustments to service lives and net salvage rates, changes in the mix of plant investments among primary accounts and changes in the age distributions of surviving plant.

Of the 68 accounts included in the 2014 study, Foster Associates is recommending rate reductions for 58 plant accounts and rate increases for 10 accounts.

Table 3 below provides a summary of the changes in annual depreciation rates and accruals recommended for the Gila River Power Station.

Function	Accrual Rate			2015 Annualized Accrual		
	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Intangible Plant	2.37%	2.37%	0.00%	$ 65,714	$ 65,714	$ -
Other Production	2.26%	2.62%	0.36%	1,903,303	2,208,345	305,042
Transmission	3.02%	1.54%	-1.48%	98,268	50,272	(47,996)
General Plant	2.76%	2.84%	0.08%	18,292	18,825	533
Total Utility	2.29%	2.58%	0.29%	$ 2,085,577	$ 2,343,156	$ 257,579

Table 3. Gila River Power Station

It should be noted, however, that depreciation rates and accruals for Gila River displayed in Table 3 were derived from plant and reserve balances at December 31, 2014, whereas rates and annualized accruals displayed in Table 2 were derived from plant and reserve balances at December 31, 2013. This timing difference is attributable to the acquisition of Gila River at the end of 2014.

The composite accrual rate recommended for Gila River is 2.58 percent. The current equivalent rate is 2.29 percent. The recommended change in the composite rate is an increase of 0.29 percentage points.

A continued application of current rates would provide 2015 annualized depreciation expense of $2,085,577 compared with an annualized expense of $2,343,156 using the proposed rates.

Q. **DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A. Yes, it does.

Exhibit REW-1

Exhibit REW–1

2014 Depreciation Rate Study

UniSourceEnergy SERVICES

– UNS Electric, Inc.

foster associates

Contents

ANALYSIS SECTION V

EXECUTIVE SUMMARY

INTRODUCTION

This report presents the findings and recommendations developed in a 2014 depreciation study for utility plant owned and operated by UNS Electric, Inc. (UNS Electric or UNSE), an operating subsidiary of UniSource Energy Services, Inc. Work on the study commenced in May 2014 and progressed through mid–January 2015 at which time the project was completed.

Foster Associates is a public utility economics consulting firm offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by the firm's Fort Myers, Florida office include property life forecasting, technological forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken numerous depreciation engagements for both public and privately owned business entities including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer software for conducting depreciation and valuation studies.

Depreciation rates currently used by UNS Electric were developed in a 2009 technical update of a full study conducted in 2006.[1] Rates developed in the 2009 update were approved by the Arizona Corporation Commission (ACC) in Docket No. E–04204A–09–0206 (Decision No. 71914, dated September 30, 2010). Depreciation rates approved in Decision No. 71914 were retained in Docket No. E–04204A–12–0504 (Decision No. 74235, dated December 31, 2013).

With the exception of transportation equipment and proposed amortizable categories, projection lives and projection curves recommended in the 2006 study were derived from parameters estimated in a 1991 study conducted by Citizens Utilities Company (Citizens), the prior owner of assets acquired by UNS Electric in 2003.

The database used in conducting the 2006 study contained plant accounting transactions for activity years 1999–2005. Without exception, life tables constructed over this limited historical period exhibited uniformly high degrees of censoring and indeterminate measurements of service life. These results were di-

[1] Unlike a full depreciation study in which projection curves, projection lives and future net salvage rates are estimated from a statistical analysis of recorded retirements and net salvage realized in the past, a technical update generally retains the parameters currently used by the utility and adjusts depreciation rates for known and measurable changes in the age distributions of surviving plant, depreciation reserves, and average net salvage rates due to the passage of time. A technical update is intended to align depreciation rates with the accounting year the rates will become effective.

rectly attributable to insufficient retirement experience over the available band of activity years.

Limitations in conducting a life analysis were exacerbated by the transfer of plant accounting records to UNS Electric from Citizens. Plant activity over the period September 2003–December 31, 2004 was processed by UNS Electric in 2005. This unavoidable delay produced a discontinuity in the available plant history, further reducing the likelihood of deriving meaningful statistical indications.

Pending the availability of sufficient retirement activity to conduct a comprehensive depreciation study, it was the opinion of Foster Associates that parameters approved in the 1991 study conducted by Citizens provided the best available estimate of service life statistics and future net salvage rates for the 2006 study. Parameters for transportation equipment (not included in the Citizens study) were adopted from a UNS Gas study conducted by Foster Associates in 2006. Projection lives approved for Citizens were adopted as amortization periods for proposed amortization categories.

At the request of UNSE, the 2014 study includes the development of 2015 depreciation rates for Gila River Power Station Unit 3. In December 2014, UNSE purchased a 25 percent interest in Unit 3 from Entegra Power Group, LLC. The remaining 75 percent interest was purchased by TEP. Gila River Unit 3 is a gas–fired combined cycle unit with a nominal capacity rating of 550 MW.

Current depreciation rates adopted for Gila River were developed by TEP using rates currently approved for UNSE Account 352.00 (Structures and Improvements); Account 353.00 (Station Equipment); Account 390.00 (Structures and Improvements); Account 392.C0 (Transportation Equipment) and Account 393.00 (Stores Equipment). Current remaining–life rates for Other Production accounts were developed using an estimated service life of 45 years with zero net salvage. A 5–year service life was estimated for Account 303.00 (Control Software).

The principal findings and recommendations of the current study are summarized in Section IV of this report. Statement A provides a comparative summary of current and proposed annual depreciation rates for each rate category. Statement B provides a comparison of current and proposed annual depreciation accruals. Statement C provides a comparison of recorded, computed and rebalanced depreciation reserves for each rate category. Statement D provides a summary of the investment and net salvage components of rebalanced reserves. Statement E provides a summary of the components used to obtain weighted–average net salvage rates. Statement F provides the computation of estimated future net salvage rates for other production facilities. Statement G provides a comparative summary of current and proposed parameters including projection life, projection curve and future net salvage rates. Statement G also contains current and proposed statistics including average service life, average remaining life, and average net salvage rates. A companion set of statements is provided in Section IV for the Gila River Power Station.

SCOPE OF STUDY

The principal activities undertaken in the course of the current study included:

- Collection of plant and net salvage data;
- Reconciliation of data to the official records of the Company;
- Discussions with UNSE plant accounting personnel;
- Validation of final retirement dates for life–span categories;
- Statistical studies of historical retirement activity;
- Estimation of projection lives and retirement dispersion patterns;
- Analysis of gross salvage and cost of removal;
- Analysis of recorded depreciation reserves; and
- Development of recommended accrual rates for each rate category.

DEPRECIATION SYSTEM

A depreciation rate is formed by combining the elements of a depreciation system. A depreciation system is composed of a method, a procedure and a technique. A depreciation method (*e.g.*, straight–line) describes the component of the system that determines the acceleration or deceleration of depreciation accruals in relation to either time or use. A depreciation procedure (*e.g.*, vintage group) identifies the level of grouping or sub–grouping of assets within a plant category. The level of grouping specifies the weighting used to obtain composite life statistics for an account. A depreciation technique (*e.g.*, remaining–life) describes the life statistic used in the system.

With the exception of amortizable categories, UNS Electric is currently using a depreciation system composed of the straight–line method, broad group procedure, remaining–life technique for all depreciable plant categories. The current system for depreciable categories was approved by the ACC in Docket No. E–1032–92–073 without comment as to the appropriateness of the system or a consideration of alternative systems. The current system was retained in the 2006 study and 2009 update pending estimation of revised parameters in a future depreciation study.

The matching and expense recognition principles of accounting provide that the cost of an asset (or group of assets) should be allocated to operations over an estimate of the economic life of the asset in proportion to the consumption of service potential. It is the opinion of Foster Associates that the objectives of depreciation accounting can be more nearly achieved using the vintage group procedure combined with the remaining–life technique. Unlike the broad group procedure in which each vintage is estimated to have the same average service life, the vintage group procedure distinguishes average service lives among vintages and provides cost apportionment over the estimated weighted–average remaining life or average life of a rate category.

The grouping of assets defined by the broad group procedure is the total plant in service from all vintages in an account where each vintage is estimated to have the same average service life. It is unlikely, therefore, that compensating deviations (*i.e.*, over and underestimates of average service life) will be created among vintages to achieve cost allocation over the average service life of each vintage.

The grouping of assets defined by the vintage group procedure is the plant in service from each vintage where the average service life (or remaining life) is estimated independently for each vintage and composite life statistics are computed for each plant account. It is more likely that compensating deviations will be created with a vintage group procedure than with a broad group procedure. Adoption of the vintage group procedure for UNS Electric will establish consistency with the procedure approved for TEP.

RECOMMENDED DEPRECIATION RATES

Table 1 below provides a summary of the changes in annual depreciation rates and accruals resulting from an application of the depreciation system and parameters recommended for UNSE in the 2014 study.

	Accrual Rate			2014 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Intangible Plant	4.69%	4.61%	-0.08%	$ 369,214	$ 363,320	$ (5,894)
Other Production	2.99%	2.80%	-0.19%	3,232,974	3,027,404	(205,570)
Transmission	3.54%	1.87%	-1.67%	3,483,939	1,849,081	(1,634,858)
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General Plant	7.44%	6.10%	-1.34%	2,643,971	2,167,254	(476,717)
Total Utility	3.94%	1.99%	-1.95%	$ 25,750,303	$ 13,016,681	$ (12,733,622)

Table 1. Current and Proposed Rates and Accruals

The composite accrual rate recommended for UNS Electric is 1.99 percent. The current equivalent rate is 3.94 percent. The recommended change in the composite rate is a reduction of 1.95 percentage points.

A continued application of current rates would provide 2014 annualized depreciation expense of $25,750,303 compared with an annualized expense of $13,016,681 using the proposed rates. The resulting 2014 expense reduction of $12,733,622 is largely attributable to a adjustments to service lives and net salvage rates, changes in the mix of plant investments among primary accounts and changes in the age distributions of surviving plant.

Of the 68 accounts included in the 2014 study, Foster Associates is recommending rate reductions for 58 plant accounts and rate increases for 10 accounts.

Table 2 below provides a summary of the changes in annual depreciation rates and accruals recommended for the Gila River Power Station. It should be noted, however, that depreciation rates and accruals for Gila River displayed in Table 2 were derived from plant and reserve balances at December 31, 2014, whereas rates and annualized accruals displayed in Table 1 were derived from plant and reserve balances at December 31, 2013. This timing difference is attributable to the acquisition of Gila River at the end of 2014.

Function	Accrual Rate			2015 Annualized Accrual		
	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Intangible Plant	2.37%	2.37%	0.00%	$ 65,714	$ 65,714	$ -
Other Production	2.26%	2.62%	0.36%	1,903,303	2,208,345	305,042
Transmission	3.02%	1.54%	-1.48%	98,268	50,272	(47,996)
General Plant	2.76%	2.84%	0.08%	18,292	18,825	533
Total Utility	2.29%	2.58%	0.29%	$ 2,085,577	$ 2,343,156	$ 257,579

Table 2. Gila River Power Station

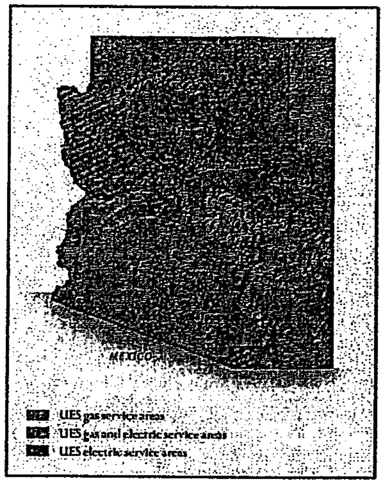
The composite accrual rate recommended for Gila River is 2.58 percent. The current equivalent rate is 2.29 percent. The recommended change in the composite rate is an increase of 0.29 percentage points.

A continued application of current rates would provide 2015 annualized depreciation expense of $2,085,577 compared with an annualized expense of $2,343,156 using the proposed rates.

Of the 13 accounts included in the 2015 study, Foster Associates is recommending rate reductions for 5 plant accounts and rate increases for 8 accounts.

COMPANY PROFILE

GENERAL



UNS Electric (UNSE) provides electric utility services to portions of Mohave and Santa Cruz Counties in Arizona. The Company serves approximately 74,000 customers in Mohave County and over 19,000 customers in Santa Cruz County. Approximately 88 percent of UNSE customers are residential, 11 percent are commercial and less than 1 percent are industrial. The average number of retail customers grew by less than 1 percent annually over the period 2010 through 2013.

Major communities served are Lake Havasu City and Kingman in Mohave County. Lake Havasu City is a premier tourist destination in the southwest. Major industry in Lake Havasu City consists of boat manufacturing and Sterilite Industries, a plastic containers manufacturer. Kingman has a strong manufacturing base, producing products such as electrical wiring, plastic conduit, building insulation, paper products, and finished cabinets.

Nogales is located on the Mexican border and is Arizona's inland port for a billion–dollar produce transportation industry. The Maquiladora, or twin plant industry, is also an important economic engine for the area. These plants provide shipping and supplies for manufacturers located in the sister city of Nogales, Sonora in Mexico.

ELECTRIC UTILITY OPERATIONS

UNSE owns and operates Black Mountain Generating Station (BMGS), a 90 MW gas–fired facility located near Kingman, Arizona. In July 2011, UNS Electric purchased BMGS from Unisource Energy Development Company (UED). UNS Gas purchases and transports natural gas to BMGS for UNSE under long–term natural gas transportation and sales agreements.

UNSE also owns and operates the Valencia Power Plant (Valencia), located in Nogales, Arizona. Valencia consists of four gas and diesel–fueled combustion turbine units and provides approximately 62 MW of peaking resources. The facility is directly interconnected with the distribution system serving the city of Nogales and the surrounding areas. In December 2013, UNSE entered into an agreement to purchase 25 percent of Gila River Unit 3 (137 MW) with TEP purchasing the remaining 75 percent interest (413 MW).

UNSE imports the power generated at BGMS into its Mohave County service territory over Western Area Power Administration's (WAPA) transmission lines. UNSE has transmission service agreements with WAPA for its transmission capacity that expire in June 2016. UNSE imports the power generated at Valencia into its Santa Cruz County service territory over its own transmission lines.

UNSE completed construction of a 138 kV transmission line from Tucson to Nogales at the end of 2013. This project replaces a 115 kV transmission line that previously linked UNSE's load to the WAPA system. The new transmission line now connects UNSE's load in Nogales directly to TEP's high voltage transmission system. The connection to TEP's system eliminates a requirement to run local generation in Nogales that was required due to limitations on the WAPA system.

UNSE employs 143 personnel in operations, engineering, customer service, billing services and administration.

STUDY PROCEDURE

INTRODUCTION

The purpose of a depreciation study is to analyze the mortality characteristics, net salvage rates and adequacy of the depreciation accrual and recorded depreciation reserve for each rate category. The current study provides the foundation and documentation for recommended changes in the depreciation accrual rates used by UNS Electric. The proposed rates are subject to approval by the Arizona Corporation Commission.

SCOPE

The steps involved in conducting the 2014 depreciation study can be grouped into five major tasks:

- Data Collection;
- Life Analysis and Estimation;
- Net Salvage Analysis;
- Depreciation Reserve Analysis; and
- Development of Accrual Rates.

The scope of the 2014 study included a consideration of each of these tasks as described below.

DATA COLLECTION

The minimum database required to conduct a statistical life study consists of a history of vintage year additions and unaged activity year retirements, transfers and adjustments. These data must be appropriately adjusted for transfers, sales and other plant activity that would otherwise bias the measured service life of normal retirements. The age distribution of surviving plant for unaged data can be estimated by distributing plant in service at the beginning of a study year to prior vintages in proportion to the theoretical amount surviving from a projection or survivor curve identified in a life study. The statistical methods of life analysis used to examine unaged plant data are known as *semi–actuarial techniques*.

A far more extensive database is required to apply statistical methods of life analysis known as *actuarial techniques*. Plant data used in an actuarial life study most often include age distribution of surviving plant at the beginning of a study year and the vintage year, activity year, and dollar amounts associated with normal retirements, reimbursed retirements, sales, abnormal retirements, transfers, corrections, and extraordinary adjustments over a series of prior activity years. An actuarial database may include age distributions of surviving plant at the beginning of the earliest activity year, rather than at the beginning of the study year. Plant additions, however, must be included in a database containing an opening age distribution to derive aged survivors at the beginning of the study year. All activity year transactions with vintage year identification are coded and stored in a data file. These data are processed by a computer program and transaction summary reports are created in a format reconcilable to the Company's official plant records. The availability of such detailed information is dependent upon an accounting system that supports aged property records. The Continuing Property Record (CPR) system used by UNSE provides aged transactions for all plant accounts.

The database used in conducting the current study was constructed by appending plant and reserve transactions recorded over the period 2009–2013 to the database used in conducting the 2009 update. The accuracy and completeness of the appended transactions was verified by comparisons to FERC Form 1 for activity years 2009–2013. The 2014 study database contains aged plant transactions over the 14–year period 1999–2013.

The database used in conducting the 2009 update was constructed by appending plant and depreciation reserve transactions recorded over the period 2006–2008 to the database used in conducting the 2006 study. The accuracy and completeness of the appended transactions was verified by comparisons to FERC Form 1 for activity years 2006–2008.

The database used in conducting the 2006 study was assembled by Foster Associates from two sources. The first source was electronic files obtained from Citizens Communications Company containing: a) aged transfers and retirements over the period 1999–August 2003; and b) age distributions of surviving plant at December 31, 2002. The second data source was electronic files obtained from UNS Electric containing plant and reserve activity over the period September 2003–December 2005 and age distributions of surviving plant at December 31, 2005.

The transfer of assets to UNSE from Citizens prevented reconciling the assembled database to any public reports of Citizens. The integrity of the database, however, was verified for activity years 2004 and 2005 for data provided by UNSE.

The database used for Gila River Power Station consisted of age distributions and recorded depreciation reserves at December 31, 2014.

LIFE ANALYSIS AND ESTIMATION

Life analysis and life estimation are terms used to describe a two–step procedure for estimating the mortality characteristics of a plant category. The first step (*i.e.*, life analysis) is largely mechanical and primarily concerned with history. Statistical techniques are used in this step to obtain a mathematical description of the forces of retirement acting upon a plant category and an estimate of the *projection life* of the account. The mathematical expressions used to describe these life characteristics are known as *survival functions* or *survivor curves*.

The second step (*i.e.*, life estimation) is concerned with predicting the expected remaining life of property units still exposed to forces of retirement. It is a process of blending the results of a life analysis with informed judgment (including expectations about the future) to obtain an appropriate projection life and curve descriptive of the parent population from which a plant account is viewed as a random sample. The amount of weight given to a life analysis will depend upon the extent to which past retirement experience is considered descriptive of the future.

The analytical methods used in a life analysis are broadly classified as actuarial and semi–actuarial techniques. Actuarial techniques can be applied to plant accounting records that reveal the age of a plant asset at the time of its retirement from service. Stated differently, each property unit must be identifiable by date of installation and age at retirement. Semi–actuarial techniques can be used to derive service life and dispersion estimates when age identification of retirements is not maintained or readily available. Age identification of retirements was available for all plant accounts included in the 2014 UNSE depreciation study.

An actuarial life analysis program designed and developed by Foster Associates was used in this study. The first step in an actuarial analysis involves a systematic treatment of the available data for the purpose of constructing an observed life table. A complete life table contains the life history of a group of property units installed during the same accounting period and various probability relationships derived from the data. A life table is arranged by age–intervals (usually defined as one year) and shows the number of units (or dollars) entering and leaving each age–interval and probability relationships associated with this activity. A life table minimally shows the age of each survivor and the age of each retirement from a group of units installed in a given accounting year.

A life table can be constructed in any one of at least five methods. The annual–rate or retirement–rate method was used in this study. The mechanics of the annual–rate method require the calculation of a series of ratios obtained by dividing the number of units (or dollars) surviving at the beginning of an age interval into the number of units (or dollars) retired during the same interval. This ratio—called a "retirement ratio" is an estimator of the hazard rate or conditional probability of retirement during an age interval. The cumulative proportion surviving is obtained by multiplying the retirement ratio for each age interval by the proportion of the original group surviving at the beginning of that age interval and subtracting this product from the proportion surviving at the beginning of the same interval. The annual–rate method is applied to multiple groups or vintages by combining the retirements and/or survivors of like ages for each vintage included in the analysis.

The second step in an actuarial analysis involves graduating or smoothing the observed life table and fitting the smoothed series to a family of survival functions. The functions used in this study are the Iowa–type curves which are mathematically described by the Pearson frequency curve family. Observed life tables were smoothed by a weighted least–squares procedure in which first, second and third degree orthogonal polynomials were fitted to the observed retirement ratios. The resulting function was expressed as a survivorship function and numerically integrated to obtain an estimate of the projection life. The smoothed survivorship function was then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data.

The set of computer programs used in the UNSE study provides multiple rolling, shrinking and progressive–band analyses of an account. Observation bands are defined by a "retirement era" that restricts the analysis to the retirement activity of all vintages represented by survivors at the beginning of a selected era. In a rolling–band analysis, a year of retirement experience is added to each successive retirement band and the earliest year from the preceding band is dropped. A shrinking–band analysis begins with the total retirement experience available and the earliest year from the preceding band is dropped for each successive band. A progressive–band analysis adds a year of retirement activity to a previous band without dropping earlier years from the analysis. Rolling, shrinking and progressive band analyses are used to detect the emergence of trends in the behavior of the dispersion and projection life.

While actuarial and semi–actuarial statistical methods are well suited to an analysis of plant categories containing a large number of homogeneous units (*e.g.*, meters or services), retirement dispersion is also exhibited in plant categories composed of major items of plant that will most likely be retired as a single unit. Plant retirements from an integrated system prior to the retirement of the entire facility are viewed as interim retirements that will be replaced in order to maintain the integrity of the system. Additionally, plant facilities may be added to the existing system (*i.e.*, interim additions) in order to expand or enhance its productive capacity without extending the service life of the existing system. A proper depreciation rate can be developed for an integrated system using a life–span method with interim retirements described by an appropriate survivor curve. Plant accounts classified in Other Production were identified by location and treated as life–span categories in the 2014 study.

As noted above, the database for UNSE contains plant accounting transactions for activity years 1999–2013. While it is theoretically possible to obtain life indications from an actuarial analysis of a single activity year, retirements during the year must be widely distributed over the beginning–of–year surviving vintages of a nearly mature plant account.[2] A similar limitation applies to the current database of UNSE which now contains only 14 activity years. Retirements must be sufficiently distributed across vintages within these 14 years to obtain meaningful service life indications from a statistical analysis.

Life tables were constructed for each plant account for which retirements were recorded over the period 1999–2013. With few exceptions, life tables constructed over this limited historical period continue to exhibit uniformly high degrees of censoring and indeterminate measurements of service life. These results are again attributable to insufficient retirement experience over the available band of activity years.

Parameters recommended by Foster Associates for accounts in which actuarial analyses failed to produce meaningful service–life indications are those approved for TEP in Docket No. E–01933A–12–0291 (Decision No. 73912, June 27, 2013). Parameters approved for TEP are considered reasonable placeholders for UNSE until sufficient retirement activity produces meaningful service life indications. It can be expected, however, that service life and net salvage statistics for UNSE will gradually converge to those estimated for TEP given that construction standards, maintenance policies and plant accounting practices are common to both TEP and UNSE.

NET SALVAGE ANALYSIS

Depreciation rates designed to achieve the goals and objectives of depreciation accounting will include a parameter for future net salvage and a variable for average net salvage reflecting both realized and future net salvage rates.

An estimate of the net salvage rate applicable to future retirements is most often obtained from an analysis of gross salvage and cost of removal realized in the past. An analysis of past experience (including an examination of trends over time) provides an appropriate basis for estimating future salvage and cost of removal. However, consideration should also be given to events that may cause deviations from net salvage realized in the past. Among the factors that should be considered are the age of plant retirements; the portion of retirements likely to be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the projection life curve; and economic conditions that may warrant greater or lesser weight to be given to net salvage rates observed in the past.

Special consideration should also be given to the treatment of insurance proceeds and other forms of third–party reimbursements credited to the depreciation reserve. A properly conducted net salvage study will exclude such activity from the estimate of future parameters and include the activity in the computation of realized and average net salvage rates.

A five–year moving average analysis of the ratio of realized salvage and cost of removal to the associated retirements was used in the 2014 study to: a) estimate

[2] Plant maturity is achieved when the age distribution of surviving plant approaches a complete survivor curve descriptive of the forces of retirement acting upon the plant category.

realized net salvage rates; b) detect the emergence of historical trends; and c) obtain a basis for estimating future net salvage rates. Cost of removal and salvage opinions obtained from Company personnel were blended with judgment and historical net salvage indications in developing estimates of the future.

Future net salvage rates for combustion turbine units (*i.e.*, Black Mountain and Valencia) were developed from the projected cost of dismantling these facilities estimated in a 2011 demolition study commissioned by TEP. Terminal net salvage for photovoltaic solar power facilities (*i.e.*, La Senita and Rio Rico) were estimated by UNSE in an asset retirement obligation study. Terminal dismantlement costs are summarized in Table 3 below.

Plant	Demolition Cost Year	Demolition Cost Cost	Ownership Share	Inflation Rate	AYFR	Trended Cost
A	B	C	D	E	F	G
Black Mountain						
Environmental	2011	$ 351,048	100.00%	2.00%	2053	$ 806,443
Non-Environmental	2011	1,419,952	100.00%	2.00%	2053	3,261,977
Total Black Mountain		$1,771,000				$4,068,420
Valencia						
Environmental	2011	$ 31,206	100.00%	2.00%	2051	$ 68,904
Non-Environmental	2011	1,101,794	100.00%	2.00%	2051	2,432,805
Total Valencia		$1,133,000				$2,501,709
La Senita	2011	$ 429,425	100.00%	2.00%	2036	$ 704,517
Rio Rico	2013	$1,350,000	100.00%	2.00%	2039	$2,259,114

Table 3. Dismantlement Costs (Other Production)

Foster Associates was requested by UNSE to develop terminal net salvage rates for Gila River Unit 3 using dismantlement costs estimated in a 2011 demolition study conducted for the Luna plant owned by TEP. Terminal dismantlement costs for Gila River are summarized in Table 4 below.

Plant	Demolition Cost Year	Demolition Cost Cost	Ownership Share	Inflation Rate	AYFR	Trended Cost
A	B	C	D	E	F	G
Gila River						
Unit 3	2011	$ 11,839,658	25.00%	2.00%	2048	$ 6,158,650
Common	2011	1,614,499	25.00%	2.00%	2048	839,816
Total Gila River		$ 13,454,157				$ 6,998,466

Table 4. Dismantlement Costs (Gila River)

The computation of future net salvage rates is shown in Statement E. The computation of the estimated average net salvage rate for each rate category is shown in Statement D.

DEPRECIATION RESERVE ANALYSIS

The purpose of a depreciation reserve analysis is to compare the current level of a recorded reserve with the level required to achieve the goals or objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized as predicted. The difference between a required (or theoretical) depreciation reserve and the recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to eliminate the reserve imbalance.

Unlike a recorded reserve which represents the net amount of depreciation expense charged to previous periods of operations, a theoretical reserve is a measure of the implied reserve requirement at the beginning of a study year if the timing of future retirements and net salvage is in exact conformance with a survivor curve chosen to predict the probable life of property still exposed to the forces of retirement. Stated differently, a theoretical depreciation reserve is the difference between the recorded cost of plant currently in service and the sum of depreciation expense and net salvage that will be charged in the future if retirements are distributed over time according to a specified retirement frequency distribution.

The survivor curve used in the calculation of a theoretical depreciation reserve is intended to describe forces of retirement that will be operative in the future. However, retirements caused by forces such as accidents, physical deterioration and changing technology seldom, if ever, remain stable over time. It is unlikely, therefore, that a probability or retirement frequency distribution can be identified that will accurately describe the age of plant retirements over the complete life cycle of a vintage. It is for this reason that depreciation rates should be reviewed periodically and adjusted for observed or predicted changes in the parameters chosen to describe the underlying forces of mortality.

Although reserve records are commonly maintained by various account classifications, the sum of all reserves is the most important measurement of the condition of depreciation reserves. If statistical life studies have not been conducted recently or retirement dispersion has been ignored in setting depreciation rates, it is likely that some accounts will be over–depreciated and other accounts will be under–depreciated relative to a calculated theoretical reserve. Differences between a theoretical reserve and a recorded reserve also will arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. It is appropriate, therefore, and consistent with group depreciation theory to periodically redistribute or rebalance recorded reserves among the various primary accounts based upon the most recent estimates of retirement dispersion and net salvage rates.

A redistribution of recorded reserves is considered appropriate for UNSE at this time. Offsetting reserve imbalances attributable to both the passage of time and parameter adjustments recommended in the current review should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability.

A redistribution of the recorded reserve for depreciable plant was achieved by multiplying the calculated reserve for each primary account within a function or location by the ratio of the total recorded reserves to the calculated total net reserve. The sum of the redistributed reserves is, therefore, equal to the total recorded depreciation reserve before the redistribution.

Depreciation reserves for amortizable categories were redistributed by setting the recorded reserves for the proposed amortization accounts equal to the theoretical reserves derived from the proposed amortization periods and distributing the residual imbalances to the remaining depreciable accounts.

Statement C provides a comparison of the computed, recorded and redistributed reserves at December 31, 2013. The recorded reserve was $287,769,189 or 44.0 percent of the depreciable plant investment. The corresponding computed reserve is $166,737,609 or 25.5 percent of the depreciable plant investment. A proportionate amount of the measured reserve excess of $121,031,580 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates developed in this study.

The recorded reserve for Gila River at December 31, 2014 was $21,791,830 or 24.0 percent of the depreciable plant investment. The corresponding computed reserve is $22,469,391 or 24.7 percent of the depreciable plant investment. A proportionate amount of the measured reserve shortfall of $677,561 will be amortized over the composite weighted–average remaining life of each rate category.

Development of Accrual Rates

The goal or objective of depreciation accounting is cost allocation over the economic life of an asset in proportion to the consumption of service potential. Ideally, the cost of an asset—which represents the cost of obtaining a bundle of service units—should be allocated to future periods of operation in proportion to the amount of service potential expended during an accounting interval. The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non–cash expenses) or cash inflows attributable to the use of that asset alone.

Cost allocation in proportion to the consumption of service potential is often approximated by the use of depreciation methods employing time rather than net revenue as the apportionment base. Examples of time–based methods include sinking–fund, straight–line, declining balance, and sum–of–the–years' digits. The advantage of using a time–based method is that it does not require an estimate of the remaining amount of service capacity an asset will provide or the amount of capacity actually consumed during an accounting interval. Using a time–based allocation method, however, does not change the goal of depreciation accounting. If it is predictable that the net revenue pattern of an asset will either decrease or increase over time, then an accelerated or decelerated time–based method should be used to approximate the rate at which service potential is actually consumed.

The time period over which the cost of an asset will be allocated to operations is determined by the combination of a procedure and a technique. A depreciation procedure describes the level of grouping or sub–grouping of assets within a plant category. The broad group, vintage group, equal–life group, and item (or unit) are a few of the more widely used procedures. A depreciation technique describes the life statistic used in a depreciation system. The whole life and remaining life (or expectancy) are the most common techniques.

Depreciation rates recommended in the current study were developed using the straight–line method, vintage group procedure, remaining–life technique. This formulation of an accrual rate is equivalent to a straight–line method, vintage group procedure, whole–life technique with amortization of reserve imbalances over the estimated remaining life of each rate category. It is the opinion of Foster Associates that this system will remain appropriate for UNSE, provided depreciation studies are conducted periodically and parameters are routinely adjusted to reflect changing operating conditions. Although the emergence of economic factors such as restructuring and performance based regulation may ultimately encourage abandonment of the straight–line method, no attempt was made in the current study to address this concern.

It is also the opinion of Foster Associates that amortization accounting currently approved for selected general support asset accounts is consistent with the goals and objectives of depreciation accounting and remains appropriate for these plant categories.

The treatment of amortization accounts in the current study was designed to produce annualized accruals equivalent to applying a rate equal to the reciprocal of an amortization period to plant balances after retirements have been recorded. Applying a rate equal to the reciprocal of the amortization period to plant balances prior to posting retirements would overstate the annualized amortization expense. Accrual rates contained in Statement A have been applied to plant balances containing vintages that will be retired upon approval of the proposed amortization periods. Accrual rates contained in Statement A should be applied to current plant balances. Accrual rates equal to the reciprocal of the amortization period should be applied to these categories after plant balances have been reduced by all vintages that have achieved an age equal to the amortization period.

STATEMENTS

INTRODUCTION

This section provides a comparative summary of depreciation rates, annual depreciation accruals, recorded and computed depreciation reserves, and current and proposed service life statistics recommended for UNS Electric. The content of these statements is briefly described below.

- Statement A provides a comparative summary of current and proposed annual depreciation rates using the vintage group procedure, remaining–life technique.
- Statement B provides a comparison of current and proposed annualized 2014 depreciation accruals derived from an application of the depreciation rates contained in Statement A.
- Statement C provides a comparison of recorded, computed and redistributed reserves at December 31, 2013 and sets forth the computations used to redistribute recorded reserves among primary plant accounts.
- Statement D provides a summary of the investment and net salvage components of rebalanced reserves.
- Statement E provides a summary of the components used to obtain a weighted–average net salvage rate for each rate category.
- Statement F provides the computation of estimated future net salvage rates for other production facilities.
- Statement G provides a comparative summary of current and proposed parameters including projection life, projection curve and future net salvage rates. Statement G also contains current and proposed statistics including average service life, average remaining life and average net salvage rates.

Current and proposed remaining life accrual rates (Statement A) are given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Reserve Ratio} - \text{Future Net Salvage Rate}}{\text{Remaining Life}}$$

This formulation of the accrual rate is equivalent to

$$\text{Accrual Rate} = \frac{1.0 - \text{Average Net Salvage}}{\text{Average Life}} + \frac{\text{Computed Reserve} - \text{Recorded Reserve}}{\text{Remaining Life}}$$

where Average Net Salvage, Computed Reserve and Recorded Reserve are expressed in percent.

UNS ELECTRIC, INC.

Statement A

Component Accrual Rates

Current: BG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2013)			Proposed (at 12/31/2013)		
	Investment	Net Salvage	Total	Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
INTANGIBLE PLANT						
Depreciable						
303.WP Misc.Intangible - WAPA Switchboard	2.82%		2.82%	2.65%		2.65%
Total Depreciable	2.82%		2.82%	2.65%		2.65%
Amortizable						
303.OT Miscellaneous Intangible Plant	← 15 Year Amortization →		3.84%	← 15 Year Amortization →		3.84%
303.WO Misc. Intangible - WAPA Fiber Optic	← 23 Year Amortization →		4.35%	← 23 Year Amortization →		4.35%
303.PC Misc.Intangible Plant - PC Software	← 5 Year Amortization →		19.32%	← 5 Year Amortization →		19.32%
Total Amortizable	6.15%		6.15%	6.15%		6.15%
Total Intangible Plant	4.69%		4.69%	4.61%		4.61%
OTHER PRODUCTION						
341.00 Structures and Improvements	2.37%		2.37%	2.29%	0.20%	2.49%
342.00 Fuel Holders, Producers and Accessories	2.55%		2.55%	2.13%	0.17%	2.30%
343.00 Prime Movers	2.53%		2.53%	2.00%	0.14%	2.14%
344.00 Generators	3.29%		3.29%	2.80%	0.30%	3.10%
345.00 Accessory Electric Equipment	2.55%		2.55%	2.27%	0.15%	2.42%
346.00 Miscellaneous Power Plant Equipment	2.62%		2.62%	2.33%	0.15%	2.48%
Total Other Production Plant	2.99%		2.99%	2.56%	0.24%	2.80%
TRANSMISSION PLANT						
350.RW Rights of Way	1.91%		1.91%	1.44%	0.14%	1.58%
352.00 Structures and Improvements	2.93%		2.93%	1.58%	0.15%	1.73%
353.00 Station Equipment	3.02%		3.02%	1.56%	-0.16%	1.40%
354.00 Towers and Fixtures	4.89%		4.89%	-1.40%	-0.33%	-1.73%
355.00 Poles and Fixtures	3.86%	0.38%	4.24%	2.53%	-0.26%	2.27%
356.00 Overhead Conductors and Devices	2.55%		2.55%	1.55%	0.12%	1.67%
358.00 Underground Conductors and Devices	1.99%	0.10%	2.09%	1.80%	0.09%	1.89%
359.00 Roads and Trails	1.93%		1.93%	0.90%	0.09%	0.99%
Total Transmission Plant	3.35%	0.19%	3.54%	2.03%	-0.16%	1.87%
DISTRIBUTION PLANT						
360.RW Rights of Way	1.95%		1.95%	0.84%	-0.01%	0.83%
361.00 Structures and Improvements	2.90%		2.90%	1.44%		1.44%
362.00 Station Equipment	3.84%		3.84%	1.43%	0.14%	1.57%
364.00 Poles, Towers and Fixtures	3.54%	0.34%	3.88%	0.90%		0.90%
365.00 Overhead Conductors and Devices	3.57%	0.35%	3.92%	1.18%		1.18%
366.00 Underground Conduit	3.49%	0.17%	3.66%	1.20%	-0.01%	1.19%
367.00 Underground Conductors and Devices	4.25%	0.02%	4.27%	1.43%	-0.01%	1.42%
368.OH Line Transformers - Overhead	4.21%	0.24%	4.45%	1.34%	0.42%	1.76%
368.UG Line Transformers - Underground	4.21%	0.24%	4.45%	1.67%	0.51%	2.18%
369.OH Services - Overhead	3.54%		3.54%	1.06%		1.06%
369.UG Services - Underground	3.61%		3.61%	1.27%		1.27%
370.00 Meters	2.90%	0.11%	3.01%	3.40%	-0.18%	3.22%
373.00 Street Lighting and Signal Systems	3.87%		3.87%	1.42%		1.42%
Total Distribution Plant	3.77%	0.20%	3.97%	1.29%	0.10%	1.39%
GENERAL PLANT						
Depreciable						
390.00 Structures and Improvements	2.60%		2.60%	2.35%	0.11%	2.46%
392.C1 Transportation Equipment - Class 1	12.35%	-0.46%	11.89%	8.78%	-0.04%	8.74%
392.C2 Transportation Equipment - Class 2	16.33%	-1.24%	15.09%	8.82%	-0.20%	8.62%
392.C3 Transportation Equipment - Class 3	19.32%	-0.94%	18.38%	9.90%	-0.13%	9.77%
392.C4 Transportation Equipment - Class 4	19.32%	-0.94%	18.38%	8.12%	-0.01%	8.11%
392.C5 Transportation Equipment - Class 5	11.88%	-0.32%	11.56%	8.10%		8.10%
392.C6 Transportation Equipment - Class 6	11.88%	-0.32%	11.56%	6.04%	-0.90%	5.14%
392.C7 Transportation Equipment - Class 7	12.33%	-1.23%	11.10%	6.81%	-0.84%	5.97%
392.C8 Transportation Equipment - Class 8	12.33%	-1.23%	11.10%	7.92%		7.92%
392.C9 Transportation Equipment - Class 9	12.33%	-1.23%	11.10%	4.71%	-0.71%	4.00%
396.00 Power Operated Equipment	6.53%		6.53%	5.37%	-0.09%	5.28%
Total Depreciable	9.68%	-0.64%	9.04%	6.21%	-0.07%	6.14%

UNS ELECTRIC, INC.
Component Accrual Rates
Current: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement A

	Account Description	Current (at 12/31/2013) Investment	Net Salvage	Total	Proposed (at 12/31/2013) Investment	Net Salvage	Total
	A	B	C	D=B+C	E	F	G=E+F
Amortizable							
391.10	Office Furniture and Equipment	← 21 Year Amortization →		3.10%	← 21 Year Amortization →		4.73%
391.20	Computer Equipment - PCs	← 5 Year Amortization →		18.86%	← 5 Year Amortization →		18.86%
393.00	Stores Equipment	← 33 Year Amortization →		3.01%	← 15 Year Amortization →		3.72%
394.00	Tools, Shop and Garage Equipment	← 29 Year Amortization →		3.42%	← 15 Year Amortization →		3.15%
395.00	Laboratory Equipment	← 40 Year Amortization →		2.50%	← 15 Year Amortization →		4.33%
397.CE	Communication Equipment	← 23 Year Amortization →		4.35%	← 15 Year Amortization →		5.79%
397.EM	Comm. Equip. - Energy Mgmt. System	← 23 Year Amortization →		4.35%	← 15 Year Amortization →		6.67%
398.00	Miscellaneous Equipment	← 18 Year Amortization →		5.52%	← 15 Year Amortization →		6.00%
	Total Amortizable	4.90%		4.90%	6.03%		6.03%
	Total General Plant	7.83%	-0.39%	7.44%	6.14%	-0.04%	6.10%
	TOTAL UTILITY	3.81%	0.13%	3.94%	1.92%	0.07%	1.99%
OTHER PRODUCTION							
Black Mountain							
341.00	Structures and Improvements	2.62%		2.62%	2.32%	0.19%	2.51%
342.00	Fuel Holders, Producers and Accessories	2.62%		2.62%	2.32%	0.15%	2.47%
343.00	Prime Movers	2.62%		2.62%	2.38%	0.14%	2.52%
344.00	Generators	2.62%		2.62%	2.32%	0.16%	2.48%
345.00	Accessory Electric Equipment	2.62%		2.62%	2.33%	0.15%	2.48%
346.00	Miscellaneous Power Plant Equipment	2.62%		2.62%	2.33%	0.14%	2.47%
	Total Black Mountain	2.62%		2.62%	2.32%	0.16%	2.48%
Enviromental							
341.00	Structures and Improvements	2.62%		2.62%	2.32%	0.22%	2.54%
342.00	Fuel Holders, Producers and Accessories	2.62%		2.62%			
343.00	Prime Movers						
344.00	Generators	2.62%		2.62%	2.32%	0.22%	2.54%
345.00	Accessory Electric Equipment	2.62%		2.62%			
346.00	Miscellaneous Power Plant Equipment	2.62%		2.62%	2.32%	0.22%	2.54%
	Total Enviromental	2.62%		2.62%	2.32%	0.22%	2.54%
Non-Enviromental							
341.00	Structures and Improvements	2.62%		2.62%	2.32%	0.15%	2.47%
342.00	Fuel Holders, Producers and Accessories	2.62%		2.62%	2.32%	0.15%	2.47%
343.00	Prime Movers	2.62%		2.62%	2.38%	0.14%	2.52%
344.00	Generators	2.62%		2.62%	2.32%	0.15%	2.47%
345.00	Accessory Electric Equipment	2.62%		2.62%	2.33%	0.15%	2.48%
346.00	Miscellaneous Power Plant Equipment	2.62%		2.62%	2.33%	0.14%	2.47%
	Total Non-Enviromental	2.62%		2.62%	2.32%	0.15%	2.47%
Valencia							
341.00	Structures and Improvements	2.05%		2.05%	2.22%	0.20%	2.42%
342.00	Fuel Holders, Producers and Accessories	2.52%		2.52%	2.05%	0.18%	2.23%
343.00	Prime Movers	2.53%		2.53%	2.00%	0.14%	2.14%
344.00	Generators	2.33%		2.33%	2.19%	0.19%	2.38%
345.00	Accessory Electric Equipment	2.35%		2.35%	2.07%	0.16%	2.23%
346.00	Miscellaneous Power Plant Equipment	2.64%		2.64%	2.30%	0.20%	2.50%
	Total Valencia	2.44%		2.44%	2.09%	0.17%	2.26%
Enviromental							
341.00	Structures and Improvements	2.05%		2.05%	2.30%	0.54%	2.84%
342.00	Fuel Holders, Producers and Accessories	2.52%		2.52%			
343.00	Prime Movers	2.53%		2.53%	2.30%	0.54%	2.84%
344.00	Generators	2.33%		2.33%	2.30%	0.54%	2.84%
345.00	Accessory Electric Equipment	2.35%		2.35%	2.30%	0.54%	2.84%
346.00	Miscellaneous Power Plant Equipment	2.64%		2.64%	2.30%	0.54%	2.84%
	Total Enviromental	2.23%		2.23%	2.30%	0.54%	2.84%

UNS ELECTRIC, INC.
Component Accrual Rates
Current: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement A

Account Description	Current (at 12/31/2013) Investment	Net Salvage	Total	Proposed (at 12/31/2013) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Non-Enviromental						
341.00 Structures and Improvements	2.05%		2.05%	2.21%	0.17%	2.38%
342.00 Fuel Holders, Producers and Accessories	2.52%		2.52%	2.05%	0.18%	2.23%
343.00 Prime Movers	2.53%		2.53%	2.00%	0.14%	2.14%
344.00 Generators	2.33%		2.33%	2.19%	0.19%	2.38%
345.00 Accessory Electric Equipment	2.35%		2.35%	2.07%	0.16%	2.23%
346.00 Miscellaneous Power Plant Equipment	2.64%		2.64%	2.30%	0.20%	2.50%
Total Non-Enviromental	2.44%		2.44%	2.09%	0.16%	2.25%
La Senita						
341.00 Structures and Improvements	2.05%		2.05%	4.15%	0.59%	4.74%
342.00 Fuel Holders, Producers and Accessories						
343.00 Prime Movers						
344.00 Generators	5.00%		5.00%	4.15%	0.59%	4.74%
345.00 Accessory Electric Equipment						
346.00 Miscellaneous Power Plant Equipment						
Total La Senita	4.98%		4.98%	4.15%	0.59%	4.74%
Rio Rico						
341.00 Structures and Improvements						
342.00 Fuel Holders, Producers and Accessories						
343.00 Prime Movers						
344.00 Generators	5.00%		5.00%	3.94%	0.64%	4.58%
345.00 Accessory Electric Equipment						
346.00 Miscellaneous Power Plant Equipment						
Total Rio Rico	5.00%		5.00%	3.94%	0.64%	4.58%

UNS ELECTRIC, INC.
Component Accruals
Current: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/13 Investment	Current 2014 Annualized Accrual Investment	Current Net Salvage	Current Total	Proposed 2014 Annualized Accrual Investment	Proposed Net Salvage	Proposed Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
INTANGIBLE PLANT								
Depreciable								
303.WP Misc.Intangible - WAPA Switchboard	$ 3,466,688	$ 97,761	$ -	$ 97,761	$ 91,867	$ -	$ 91,867	$ (5,894)
Total Depreciable	$ 3,466,688	$ 97,761	$ -	$ 97,761	$ 91,867	$ -	$ 91,867	$ (5,894)
Amortizable								
303.OT Miscellaneous Intangible Plant	$ 2,124,607	$ 81,653	$ -	$ 81,653	$ 81,653	$ -	$ 81,653	$ -
303.WO Misc. Intangible - WAPA Fiber Optic	1,685,000	73,261		73,261	73,261		73,261	
303.PC Misc.Intangible Plant - PC Software	603,292	116,539		116,539	116,539		116,539	
Total Amortizable	$ 4,412,899	$ 271,453	$ -	$ 271,453	$ 271,453	$ -	$ 271,453	$ -
Total Intangible Plant	$ 7,879,587	$ 369,214	$ -	$ 369,214	$ 363,320	$ -	$ 363,320	$ (5,894)
OTHER PRODUCTION								
341.00 Structures and Improvements	$ 4,598,337	$ 108,778	$ -	$ 108,778	$ 105,147	$ 9,198	$ 114,345	$ 5,567
342.00 Fuel Holders, Producers and Accessories	1,211,692	30,872		30,872	25,751	2,080	27,831	(3,041)
343.00 Prime Movers	13,474,281	340,905		340,905	269,693	19,110	288,803	(52,102)
344.00 Generators	64,081,268	2,109,503		2,109,503	1,794,748	193,854	1,988,602	(120,901)
345.00 Accessory Electric Equipment	12,112,434	309,466		309,466	274,654	18,497	293,151	(16,315)
346.00 Miscellaneous Power Plant Equipment	12,712,669	333,450		333,450	295,639	19,033	314,672	(18,778)
Total Other Production Plant	$ 108,190,681	$ 3,232,974	$ -	$ 3,232,974	$ 2,765,632	$ 261,772	$ 3,027,404	$ (205,570)
TRANSMISSION PLANT								
350.RW Rights of Way	$ 359,816	$ 6,872	$ -	$ 6,872	$ 5,181	$ 504	$ 5,685	$ (1,187)
352.00 Structures and Improvements	917,646	26,887		26,887	14,499	1,376	15,875	(11,012)
353.00 Station Equipment	31,252,159	943,815		943,815	487,534	(50,003)	437,531	(506,284)
354.00 Towers and Fixtures	85,731	4,192		4,192	(1,200)	(283)	(1,483)	(5,675)
355.00 Poles and Fixtures	48,683,998	1,879,202	184,999	2,064,201	1,231,705	(126,578)	1,105,127	(959,074)
356.00 Overhead Conductors and Devices	16,974,498	432,850		432,850	263,105	20,369	283,474	(149,376)
358.00 Underground Conductors and Devices	29,815	593	30	623	537	27	564	(59)
359.00 Roads and Trails	233,099	4,499		4,499	2,098	210	2,308	(2,191)
Total Transmission Plant	$ 98,536,762	$ 3,298,910	$ 185,029	$ 3,483,939	$ 2,003,459	$ (154,378)	$ 1,849,081	$ (1,634,858)
DISTRIBUTION PLANT								
360.RW Rights of Way	$ 143,806	$ 2,804	$ -	$ 2,804	$ 1,208	$ (14)	$ 1,194	$ (1,610)
361.00 Structures and Improvements	6,694,424	194,138		194,138	96,400		96,400	(97,738)
362.00 Station Equipment	62,380,383	2,395,407		2,395,407	892,039	87,333	979,372	(1,416,035)
364.00 Poles, Towers and Fixtures	93,246,417	3,300,923	317,038	3,617,961	839,218		839,218	(2,778,743)
365.00 Overhead Conductors and Devices	71,519,261	2,553,238	250,317	2,803,555	843,927		843,927	(1,959,628)
366.00 Underground Conduit	20,695,685	722,279	35,183	757,462	248,348	(2,070)	246,278	(511,184)
367.00 Underground Conductors and Devices	43,607,456	1,853,317	8,721	1,862,038	623,587	(4,361)	619,226	(1,242,812)
368.OH Line Transformers - Overhead	50,986,935	2,146,550	122,369	2,268,919	683,225	214,145	897,370	(1,371,549)
368.UG Line Transformers - Underground	22,736,128	957,191	54,567	1,011,758	379,693	115,954	495,647	(516,111)

UNS ELECTRIC, INC.
Component Accruals
Current: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

	Account Description	12/31/13 Investment	Current 2014 Annualized Accrual			Proposed 2014 Annualized Accrual			Difference
			Investment	Net Salvage	Total	Investment	Net Salvage	Total	
	A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
369.OH	Services - Overhead	10,722,066	379,561		379,561	113,654		113,654	(265,907)
369.UG	Services - Underground	6,409,742	231,392		231,392	81,404		81,404	(149,988)
370.00	Meters	10,126,264	293,662	11,139	304,801	344,293	(18,227)	326,066	21,265
373.00	Street Lighting and Signal Systems	4,920,118	190,409		190,409	69,866		69,866	(120,543)
	Total Distribution Plant	$ 404,188,685	$ 15,220,871	$ 799,334	$ 16,020,205	$ 5,216,862	$ 392,760	$ 5,609,622	$ (10,410,583)
	GENERAL PLANT								
	Depreciable								
390.00	Structures and Improvements	$ 5,086,394	$ 132,246	$ -	$ 132,246	$ 119,530	$ 5,595	$ 125,125	$ (7,121)
392.C1	Transportation Equipment - Class 1	1,692,200	208,987	(7,784)	201,203	148,575	(677)	147,898	(53,305)
392.C2	Transportation Equipment - Class 2	617,265	100,799	(7,654)	93,145	54,443	(1,235)	53,208	(39,937)
392.C3	Transportation Equipment - Class 3	984,647	190,234	(9,256)	180,978	97,480	(1,280)	96,200	(84,778)
392.C4	Transportation Equipment - Class 4	77,970	15,064	(733)	14,331	6,331	(8)	6,323	(8,008)
392.C5	Transportation Equipment - Class 5	1,385,458	164,592	(4,433)	160,159	112,222		112,222	(47,937)
392.C6	Transportation Equipment - Class 6	20,070	2,384	(64)	2,320	1,212	(181)	1,031	(1,289)
392.C7	Transportation Equipment - Class 7	511,384	63,054	(6,290)	56,764	34,825	(4,296)	30,529	(26,235)
392.C8	Transportation Equipment - Class 8	6,907,249	851,664	(84,959)	766,705	547,054		547,054	(219,651)
392.C9	Transportation Equipment - Class 9	1,484,248	183,008	(18,256)	164,752	69,908	(10,538)	59,370	(105,382)
396.00	Power Operated Equipment	3,036,519	198,285		198,285	163,061	(2,733)	160,328	(37,957)
	Total Depreciable	$ 21,803,404	$ 2,110,317	$ (139,429)	$ 1,970,888	$ 1,354,641	$ (15,353)	$ 1,339,288	$ (631,600)
	Amortizable								
391.10	Office Furniture and Equipment	$ 1,791,213	$ 55,447	$ -	$ 55,447	$ 84,767	$ -	$ 84,767	$ 29,320
391.20	Computer Equipment - PCs	1,111,667	209,646		209,646	209,646		209,646	
393.00	Stores Equipment	347,815	10,478		10,478	12,945		12,945	2,467
394.00	Tools, Shop and Garage Equipment	2,624,550	89,860		89,860	82,680		82,680	(7,180)
395.00	Laboratory Equipment	1,933,101	48,328		48,328	83,619		83,619	35,291
397.CE	Communication Equipment	4,612,973	200,434		200,434	267,152		267,152	66,718
397.EM	Comm. Equip. - Energy Mgmt. System	1,192,687	51,856		51,856	79,512		79,512	27,656
398.00	Miscellaneous Equipment	127,465	7,034		7,034	7,645		7,645	611
	Total Amortizable	$ 13,741,471	$ 673,083	$ -	$ 673,083	$ 827,966	$ -	$ 827,966	$ 154,883
	Total General Plant	$ 35,544,875	$ 2,783,400	$ (139,429)	$ 2,643,971	$ 2,182,607	$ (15,353)	$ 2,167,254	$ (476,717)
	TOTAL UTILITY	$ 654,340,590	$ 24,905,369	$ 844,934	$ 25,750,303	$ 12,531,880	$ 484,801	$ 13,016,681	$ (12,733,622)
	OTHER PRODUCTION								
	Black Mountain								
341.00	Structures and Improvements	$ 2,545,878	$ 66,702	$ -	$ 66,702	$ 59,065	$ 4,925	$ 63,990	$ (2,712)
342.00	Fuel Holders, Producers and Accessories	337,317	8,838		8,838	7,826	506	8,332	(506)
343.00	Prime Movers	5,884	154		154	140	8	148	(6)
344.00	Generators	38,465,970	1,007,809		1,007,809	892,411	62,518	954,929	(52,880)
345.00	Accessory Electric Equipment	9,194,049	240,884		240,884	214,221	13,791	228,012	(12,872)
346.00	Miscellaneous Power Plant Equipment	10,827,001	283,668		283,668	252,268	15,169	267,437	(16,231)
	Total Black Mountain	$ 61,376,099	$ 1,608,055	$ -	$ 1,608,055	$ 1,425,931	$ 96,917	$ 1,522,848	$ (85,207)

UNS ELECTRIC, INC.
Component Accruals
Current: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

	Account Description	12/31/13 Investment	Current 2014 Annualized Accrual			Proposed 2014 Annualized Accrual			Difference
			Investment	Net Salvage	Total	Investment	Net Salvage	Total	
	A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Enviromental									
341.00	Structures and Improvements	$ 1,580,293	$ 41,404	$ -	$ 41,404	$ 36,663	$ 3,477	$ 40,140	$ (1,264)
342.00	Fuel Holders, Producers and Accessories								
343.00	Prime Movers								
344.00	Generators	6,884,651	180,378		180,378	159,724	15,146	174,870	(5,508)
345.00	Accessory Electric Equipment								
346.00	Miscellaneous Power Plant Equipment	14,610	383		383	339	32	371	(12)
	Total Enviromental	$ 8,479,554	$ 222,165	$ -	$ 222,165	$ 196,726	$ 18,655	$ 215,381	$ (6,784)
Non-Enviromental									
341.00	Structures and Improvements	$ 965,585	$ 25,298	$ -	$ 25,298	$ 22,402	$ 1,448	$ 23,850	$ (1,448)
342.00	Fuel Holders, Producers and Accessories	337,317	8,838		8,838	7,826	506	8,332	(506)
343.00	Prime Movers	5,884	154		154	140	8	148	(6)
344.00	Generators	31,581,319	827,431		827,431	732,687	47,372	780,059	(47,372)
345.00	Accessory Electric Equipment	9,194,049	240,884		240,884	214,221	13,791	228,012	(12,872)
346.00	Miscellaneous Power Plant Equipment	10,812,391	283,285		283,285	251,929	15,137	267,066	(16,219)
	Total Non-Enviromental	$ 52,896,545	$ 1,385,890	$ -	$ 1,385,890	$ 1,229,205	$ 78,262	$ 1,307,467	$ (78,423)
Valencia									
341.00	Structures and Improvements	$ 2,023,551	$ 41,483	$ -	$ 41,483	$ 44,882	$ 4,102	$ 48,984	$ 7,501
342.00	Fuel Holders, Producers and Accessories	874,375	22,034		22,034	17,925	1,574	19,499	(2,535)
343.00	Prime Movers	13,468,397	340,751		340,751	269,553	19,102	288,655	(52,096)
344.00	Generators	6,706,754	156,267		156,267	146,899	12,808	159,707	3,440
345.00	Accessory Electric Equipment	2,918,385	68,582		68,582	60,433	4,706	65,139	(3,443)
346.00	Miscellaneous Power Plant Equipment	1,885,668	49,782		49,782	43,371	3,864	47,235	(2,547)
	Total Valencia	$ 27,877,130	$ 678,899	$ -	$ 678,899	$ 583,063	$ 46,156	$ 629,219	$ (49,680)
Enviromental									
341.00	Structures and Improvements	$ 178,908	$ 3,668	$ -	$ 3,668	$ 4,115	$ 966	$ 5,081	$ 1,413
342.00	Fuel Holders, Producers and Accessories								
343.00	Prime Movers	61,731	1,562		1,562	1,420	333	1,753	191
344.00	Generators	18,506	431		431	426	100	526	95
345.00	Accessory Electric Equipment	9,551	224		224	220	52	272	48
346.00	Miscellaneous Power Plant Equipment	27,463	725		725	632	148	780	55
	Total Enviromental	$ 296,159	$ 6,610	$ -	$ 6,610	$ 6,813	$ 1,599	$ 8,412	$ 1,802
Non-Enviromental									
341.00	Structures and Improvements	$ 1,844,643	$ 37,815	$ -	$ 37,815	$ 40,767	$ 3,136	$ 43,903	$ 6,088
342.00	Fuel Holders, Producers and Accessories	874,375	22,034		22,034	17,925	1,574	19,499	(2,535)
343.00	Prime Movers	13,406,666	339,189		339,189	268,133	18,769	286,902	(52,287)
344.00	Generators	6,688,248	155,836		155,836	146,473	12,708	159,181	3,345
345.00	Accessory Electric Equipment	2,908,834	68,358		68,358	60,213	4,654	64,867	(3,491)
346.00	Miscellaneous Power Plant Equipment	1,858,205	49,057		49,057	42,739	3,716	46,455	(2,602)
	Total Non-Enviromental	$ 27,580,971	$ 672,289	$ -	$ 672,289	$ 576,250	$ 44,557	$ 620,807	$ (51,482)

UNS ELECTRIC, INC.
Component Accruals
Current: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/13	Current 2014 Annualized Accrual			Proposed 2014 Annualized Accrual			
	Investment	Investment	Net Salvage	Total	Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
La Senita								
341.00 Structures and Improvements	$ 28,908	$ 593	$ -	$ 593	$ 1,200	$ 171	$ 1,371	$ 778
342.00 Fuel Holders, Producers and Accessories								
343.00 Prime Movers								
344.00 Generators	4,972,083	248,604		248,604	206,341	29,335	235,676	(12,928)
345.00 Accessory Electric Equipment								
346.00 Miscellaneous Power Plant Equipment								
Total La Senita	$ 5,000,991	$ 249,197	$ -	$ 249,197	$ 207,541	$ 29,506	$ 237,047	$ (12,150)
Rio Rico								
341.00 Structures and Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
342.00 Fuel Holders, Producers and Accessories								
343.00 Prime Movers								
344.00 Generators	13,936,461	696,823		696,823	549,097	89,193	638,290	(58,533)
345.00 Accessory Electric Equipment								
346.00 Miscellaneous Power Plant Equipment								
Total Rio Rico	$ 13,936,461	$ 696,823	$ -	$ 696,823	$ 549,097	$ 89,193	$ 638,290	$ (58,533)

UNS ELECTRIC, INC.
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2013

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
INTANGIBLE PLANT							
Depreciable							
303.WP Misc.Intangible - WAPA Switchboard	$ 3,466,688	$ 1,230,248	35.49%	$ 848,811	24.48%	$ 1,211,051	34.93%
Total Depreciable	$ 3,466,688	$ 1,230,248	35.49%	$ 848,811	24.48%	$ 1,211,051	34.93%
Amortizable							
303.OT Miscellaneous Intangible Plant	$ 2,124,607	$ 2,010,811	94.64%	$ 2,010,457	94.63%	$ 2,010,457	94.63%
303.WO Misc. Intangible - WAPA Fiber Optic	1,685,000	769,423	45.66%	769,239	45.65%	769,239	45.65%
303.PC Misc.Intangible Plant - PC Software	603,292	298,388	49.46%	318,122	52.73%	318,122	52.73%
Total Amortizable	$ 4,412,899	$ 3,078,622	69.76%	$ 3,097,818	70.20%	$ 3,097,818	70.20%
Total Intangible Plant	$ 7,879,587	$ 4,308,869	54.68%	$ 3,946,629	50.09%	$ 4,308,869	54.68%
OTHER PRODUCTION							
341.00 Structures and Improvements	$ 4,598,337	$ 689,981	15.01%	$ 762,272	16.58%	$ 838,968	18.25%
342.00 Fuel Holders, Producers and Accessories	1,211,692	329,893	27.23%	272,661	22.50%	300,629	24.81%
343.00 Prime Movers	13,474,281	4,711,283	34.97%	3,959,034	29.38%	4,368,059	32.42%
344.00 Generators	64,081,268	7,940,273	12.39%	7,120,406	11.11%	7,848,804	12.25%
345.00 Accessory Electric Equipment	12,112,434	2,172,456	17.94%	1,877,021	15.50%	2,065,603	17.05%
346.00 Miscellaneous Power Plant Equipment	12,712,669	1,391,236	10.94%	1,649,040	12.97%	1,813,060	14.26%
Total Other Production Plant	$ 108,190,681	$ 17,235,122	15.93%	$ 15,640,435	14.46%	$ 17,235,122	15.93%
TRANSMISSION PLANT							
350.RW Rights of Way	$ 359,816	$ 79,174	22.00%	$ 73,657	20.47%	$ 116,799	32.46%
352.00 Structures and Improvements	917,646	243,569	26.54%	186,031	20.27%	294,994	32.15%
353.00 Station Equipment	31,252,159	9,135,269	29.23%	5,081,937	16.26%	8,058,552	25.79%
354.00 Towers and Fixtures	85,731	(157,166)	-183.32%	74,376	86.76%	117,940	137.57%
355.00 Poles and Fixtures	48,683,998	10,381,732	21.32%	4,926,286	10.12%	7,811,733	16.05%
356.00 Overhead Conductors and Devices	16,974,498	6,849,231	40.35%	6,355,243	37.44%	10,077,665	59.37%
358.00 Underground Conductors and Devices	29,815	5,637	18.91%	4,483	15.04%	7,109	23.84%
359.00 Roads and Trails	233,099	125,125	53.68%	112,113	48.10%	177,780	76.27%
Total Transmission Plant	$ 98,536,762	$ 26,662,571	27.06%	$ 16,814,126	17.06%	$ 26,662,571	27.06%
DISTRIBUTION PLANT							
360.RW Rights of Way	$ 143,806	$ 61,060	42.46%	$ 49,779	34.62%	$ 96,648	67.21%
361.00 Structures and Improvements	6,694,424	2,635,037	39.36%	1,176,698	17.58%	2,284,615	34.13%
362.00 Station Equipment	62,380,383	26,311,395	42.18%	11,863,509	19.02%	23,033,571	36.92%
364.00 Poles, Towers and Fixtures	93,246,417	64,973,817	69.68%	34,171,522	36.65%	66,345,647	71.15%
365.00 Overhead Conductors and Devices	71,519,261	43,158,800	60.35%	19,261,172	26.93%	37,396,488	52.29%
366.00 Underground Conduit	20,695,685	9,278,435	44.83%	4,005,905	19.36%	7,777,656	37.58%

UNS ELECTRIC, INC.
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2013

Statement C

	Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
	A	B	C	D=C/B	E	F=E/B	G	H=G/B
367.00	Underground Conductors and Devices	43,607,456	21,248,929	48.73%	11,290,537	25.89%	21,921,118	50.27%
368.OH	Line Transformers - Overhead	50,986,935	33,538,395	65.78%	18,397,669	36.08%	35,719,955	70.06%
368.UG	Line Transformers - Underground	22,736,128	8,283,683	36.43%	5,446,359	23.95%	10,574,368	46.51%
369.OH	Services - Overhead	10,722,066	6,376,719	59.47%	3,815,968	35.59%	7,408,885	69.10%
369.UG	Services - Underground	6,409,742	2,842,024	44.34%	1,282,589	20.01%	2,490,208	38.85%
370.00	Meters	10,126,264	(48,637)	-0.48%	2,422,116	23.92%	4,702,654	46.44%
373.00	Street Lighting and Signal Systems	4,920,118	3,299,743	67.07%	1,137,023	23.11%	2,207,585	44.87%
	Total Distribution Plant	$ 404,188,685	$ 221,959,399	54.91%	$ 114,320,846	28.28%	$ 221,959,399	54.91%
	GENERAL PLANT							
	Depreciable							
390.00	Structures and Improvements	$ 5,086,394	$ 1,153,105	22.67%	$ 1,284,406	25.25%	$ 1,511,169	29.71%
392.C1	Transportation Equipment - Class 1	1,692,200	1,364,664	80.64%	635,885	37.58%	748,151	44.21%
392.C2	Transportation Equipment - Class 2	617,265	305,779	49.54%	222,615	36.06%	261,918	42.43%
392.C3	Transportation Equipment - Class 3	984,647	977,346	99.26%	339,730	34.50%	399,710	40.59%
392.C4	Transportation Equipment - Class 4	77,970	23,223	29.78%	9,814	12.59%	11,547	14.81%
392.C5	Transportation Equipment - Class 5	1,385,458	1,421,428	102.60%	916,218	66.13%	1,077,977	77.81%
392.C6	Transportation Equipment - Class 6	20,070	21,609	107.67%	5,766	28.73%	6,784	33.80%
392.C7	Transportation Equipment - Class 7	511,384	142,635	27.89%	71,610	14.00%	84,252	16.48%
392.C8	Transportation Equipment - Class 8	6,907,249	5,183,203	75.04%	4,159,284	60.22%	4,893,609	70.85%
392.C9	Transportation Equipment - Class 9	1,484,248	639,054	43.06%	309,416	20.85%	364,044	24.53%
396.00	Power Operated Equipment	3,036,519	1,404,331	46.25%	1,037,873	34.18%	1,221,110	40.21%
	Total Depreciable	$ 21,803,404	$ 12,636,377	57.96%	$ 8,992,616	41.24%	$ 10,580,270	48.53%
	Amortizable							
391.10	Office Furniture and Equipment	$ 1,791,213	$ 1,001,136	55.89%	$ 1,013,840	56.60%	$ 1,013,840	56.60%
391.20	Computer Equipment - PCs	1,111,667	430,957	38.77%	438,178	39.42%	438,178	39.42%
393.00	Stores Equipment	347,815	153,541	44.14%	232,696	66.90%	232,696	66.90%
394.00	Tools, Shop and Garage Equipment	2,624,550	1,290,084	49.15%	2,008,709	76.54%	2,008,709	76.54%
395.00	Laboratory Equipment	1,933,101	606,324	31.37%	1,219,122	63.07%	1,219,122	63.07%
397.CE	Communication Equipment	4,612,973	1,353,435	29.34%	1,926,935	41.77%	1,926,935	41.77%
397.EM	Comm. Equip. - Energy Mgmt. System	1,192,687	89,218	7.48%	134,439	11.27%	134,439	11.27%
398.00	Miscellaneous Equipment	127,465	42,154	33.07%	49,039	38.47%	49,039	38.47%
	Total Amortizable	$ 13,741,471	$ 4,966,850	36.14%	$ 7,022,958	51.11%	$ 7,022,958	51.11%
	Total General Plant	$ 35,544,875	$ 17,603,228	49.52%	$ 16,015,574	45.06%	$ 17,603,228	49.52%
	TOTAL UTILITY	$ 654,340,590	$ 287,769,189	43.98%	$ 166,737,609	25.48%	$ 287,769,189	43.98%

UNS ELECTRIC, INC.
Depreciation Reserve Summary
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Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
OTHER PRODUCTION							
Black Mountain							
341.00 Structures and Improvements	$ 2,545,878	$ 371,293	14.58%	$ 323,136	12.69%	$ 354,962	13.94%
342.00 Fuel Holders, Producers and Accessories	337,317	49,188	14.58%	42,051	12.47%	46,192	13.69%
343.00 Prime Movers	5,884	700	11.90%	613	10.41%	673	11.44%
344.00 Generators	38,465,970	5,574,811	14.49%	4,814,947	12.52%	5,289,175	13.75%
345.00 Accessory Electric Equipment	9,194,049	1,282,871	13.95%	1,107,457	12.05%	1,216,531	13.23%
346.00 Miscellaneous Power Plant Equipment	10,827,001	1,074,596	9.93%	1,316,284	12.16%	1,445,926	13.35%
Total Black Mountain	$ 61,376,099	$ 8,353,459	13.61%	$ 7,604,488	12.39%	$ 8,353,459	13.61%
Enviromental							
341.00 Structures and Improvements	$ 1,580,293	$ 230,485	14.58%	$ 202,765	12.83%	$ 222,735	14.09%
342.00 Fuel Holders, Producers and Accessories							
343.00 Prime Movers							
344.00 Generators	6,884,651	1,003,932	14.58%	884,923	12.85%	972,080	14.12%
345.00 Accessory Electric Equipment							
346.00 Miscellaneous Power Plant Equipment	14,610	2,130	14.58%	1,878	12.85%	2,063	14.12%
Total Enviromental	$ 8,479,554	$ 1,236,547	14.58%	$ 1,089,566	12.85%	$ 1,196,878	14.11%
Non-Enviromental							
341.00 Structures and Improvements	$ 965,585	$ 140,808	14.58%	$ 120,372	12.47%	$ 132,227	13.69%
342.00 Fuel Holders, Producers and Accessories	337,317	49,188	14.58%	42,051	12.47%	46,192	13.69%
343.00 Prime Movers	5,884	700	11.90%	613	10.41%	673	11.44%
344.00 Generators	31,581,319	4,570,879	14.47%	3,930,024	12.44%	4,317,095	13.67%
345.00 Accessory Electric Equipment	9,194,049	1,282,871	13.95%	1,107,457	12.05%	1,216,531	13.23%
346.00 Miscellaneous Power Plant Equipment	10,812,391	1,072,466	9.92%	1,314,406	12.16%	1,443,863	13.35%
Total Non-Enviromental	$ 52,896,545	$ 7,116,912	13.45%	$ 6,514,922	12.32%	$ 7,156,582	13.53%
Valencia							
341.00 Structures and Improvements	$ 2,023,551	$ 317,429	15.69%	$ 435,909	21.54%	$ 480,945	23.77%
342.00 Fuel Holders, Producers and Accessories	874,375	280,706	32.10%	230,611	26.37%	254,436	29.10%
343.00 Prime Movers	13,468,397	4,710,583	34.98%	3,958,422	29.39%	4,367,386	32.43%
344.00 Generators	6,706,754	1,401,674	20.90%	1,448,040	21.59%	1,597,644	23.82%
345.00 Accessory Electric Equipment	2,918,385	889,585	30.48%	769,564	26.37%	849,072	29.09%
346.00 Miscellaneous Power Plant Equipment	1,885,668	316,639	16.79%	332,756	17.65%	367,135	19.47%
Total Valencia	$ 27,877,130	$ 7,916,617	28.40%	$ 7,175,301	25.74%	$ 7,916,617	28.40%

UNS ELECTRIC, INC.
Depreciation Reserve Summary
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Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
Enviromental							
341.00 Structures and Improvements	$ 178,908	$ -		$ 35,417	19.80%	$ 39,076	21.84%
342.00 Fuel Holders, Producers and Accessories							
343.00 Prime Movers	61,731	11,506	18.64%	12,221	19.80%	13,483	21.84%
344.00 Generators	18,506			3,664	19.80%	4,042	21.84%
345.00 Accessory Electric Equipment	9,551	1,467	15.36%	1,891	19.80%	2,086	21.84%
346.00 Miscellaneous Power Plant Equipment	27,463			5,437	19.80%	5,998	21.84%
Total Enviromental	$ 296,159	$ 12,973	4.38%	$ 58,629	19.80%	$ 64,686	21.84%
Non-Enviromental							
341.00 Structures and Improvements	$ 1,844,643	$ 317,429	17.21%	$ 400,492	21.71%	$ 441,868	23.95%
342.00 Fuel Holders, Producers and Accessories	874,375	280,706	32.10%	230,611	26.37%	254,436	29.10%
343.00 Prime Movers	13,406,666	4,699,077	35.05%	3,946,201	29.43%	4,353,902	32.48%
344.00 Generators	6,688,248	1,401,674	20.96%	1,444,376	21.60%	1,593,602	23.83%
345.00 Accessory Electric Equipment	2,908,834	888,118	30.53%	767,673	26.39%	846,985	29.12%
346.00 Miscellaneous Power Plant Equipment	1,858,205	316,639	17.04%	327,319	17.61%	361,136	19.43%
Total Non-Enviromental	$ 27,580,971	$ 7,903,643	28.66%	$ 7,116,672	25.80%	$ 7,851,930	28.47%
La Senita							
341.00 Structures and Improvements	$ 28,908	$ 1,259	4.36%	$ 3,226	11.16%	$ 3,061	10.59%
342.00 Fuel Holders, Producers and Accessories							
343.00 Prime Movers							
344.00 Generators	4,972,083	528,273	10.62%	554,905	11.16%	526,471	10.59%
345.00 Accessory Electric Equipment							
346.00 Miscellaneous Power Plant Equipment							
Total La Senita	$ 5,000,991	$ 529,532	10.59%	$ 558,132	11.16%	$ 529,532	10.59%
Rio Rico							
341.00 Structures and Improvements	$ -	$ -		$ -		$ -	
342.00 Fuel Holders, Producers and Accessories							
343.00 Prime Movers							
344.00 Generators	13,936,461	435,514	3.13%	302,514	2.17%	435,514	3.13%
345.00 Accessory Electric Equipment							
346.00 Miscellaneous Power Plant Equipment							
Total Rio Rico	$ 13,936,461	$ 435,514	3.13%	$ 302,514	2.17%	$ 435,514	3.13%

UNS ELECTRIC, INC.
Depreciation Reserve Components
Redistributed Reserve
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Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	I=C+E+G	J=I/B
INTANGIBLE PLANT							
Depreciable							
303.WP Misc.Intangible - WAPA Switchboard	$ 3,466,688	$ 1,211,051	34.93%	$ -		$ 1,211,051	34.93%
Total Depreciable	$ 3,466,688	$ 1,211,051	34.93%	$ -		$ 1,211,051	34.93%
Amortizable							
303.OT Miscellaneous Intangible Plant	$ 2,124,607	$ 2,010,457	94.63%	$ -		$ 2,010,457	94.63%
303.WO Misc. Intangible - WAPA Fiber Optic	1,685,000	769,239	45.65%			769,239	45.65%
303.PC Misc.Intangible Plant - PC Software	603,292	318,122	52.73%			318,122	52.73%
Total Amortizable	$ 4,412,899	$ 3,097,818	70.20%	$ -		$ 3,097,818	70.20%
Total Intangible Plant	$ 7,879,587	$ 4,308,869	54.68%	$ -		$ 4,308,869	54.68%
OTHER PRODUCTION							
341.00 Structures and Improvements	$ 4,598,337	$ 753,310	16.38%	$ 85,658	1.86%	$ 838,968	18.25%
342.00 Fuel Holders, Producers and Accessories	1,211,692	277,352	22.89%	23,276	1.92%	300,629	24.81%
343.00 Prime Movers	13,474,281	3,852,272	28.59%	515,786	3.83%	4,368,059	32.42%
344.00 Generators	64,081,268	7,251,559	11.32%	597,245	0.93%	7,848,804	12.25%
345.00 Accessory Electric Equipment	12,112,434	1,907,674	15.75%	157,929	1.30%	2,065,603	17.05%
346.00 Miscellaneous Power Plant Equipment	12,712,669	1,695,081	13.33%	117,980	0.93%	1,813,060	14.26%
Total Other Production Plant	$ 108,190,681	$ 15,737,249	14.55%	$ 1,497,873	1.38%	$ 17,235,122	15.93%
TRANSMISSION PLANT							
350.RW Rights of Way	$ 359,816	$ 106,181	29.51%	$ 10,618	2.95%	$ 116,799	32.46%
352.00 Structures and Improvements	917,646	268,176	29.22%	26,818	2.92%	294,994	32.15%
353.00 Station Equipment	31,252,159	8,908,781	28.51%	(850,230)	-2.72%	8,058,552	25.79%
354.00 Towers and Fixtures	85,731	104,843	122.29%	13,097	15.28%	117,940	137.57%
355.00 Poles and Fixtures	48,683,998	8,603,485	17.67%	(791,753)	-1.63%	7,811,733	16.05%
356.00 Overhead Conductors and Devices	16,974,498	9,031,438	53.21%	1,046,227	6.16%	10,077,665	59.37%
358.00 Underground Conductors and Devices	29,815	6,770	22.71%	339	1.14%	7,109	23.84%
359.00 Roads and Trails	233,099	161,618	69.33%	16,162	6.93%	177,780	76.27%
Total Transmission Plant	$ 98,536,762	$ 27,191,293	27.60%	$ (528,722)	-0.54%	$ 26,662,571	27.06%

UNS ELECTRIC, INC.
Depreciation Reserve Components
Redistributed Reserve
December 31, 2013

Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	I=C+E+G	J=I/B
DISTRIBUTION PLANT							
360.RW Rights of Way	$ 143,806	$ 96,648	67.21%	$ -		$ 96,648	67.21%
361.00 Structures and Improvements	6,694,424	2,284,615	34.13%			2,284,615	34.13%
362.00 Station Equipment	62,380,383	20,848,459	33.42%	2,185,112	3.50%	23,033,571	36.92%
364.00 Poles, Towers and Fixtures	93,246,417	66,115,794	70.90%	229,853	0.25%	66,345,647	71.15%
365.00 Overhead Conductors and Devices	71,519,261	37,396,488	52.29%			37,396,488	52.29%
366.00 Underground Conduit	20,695,685	7,680,152	37.11%	97,505	0.47%	7,777,656	37.58%
367.00 Underground Conductors and Devices	43,607,456	21,795,377	49.98%	125,741	0.29%	21,921,118	50.27%
368.OH Line Transformers - Overhead	50,986,935	27,750,899	54.43%	7,969,056	15.63%	35,719,955	70.06%
368.UG Line Transformers - Underground	22,736,128	8,244,587	36.26%	2,329,781	10.25%	10,574,368	46.51%
369.OH Services - Overhead	10,722,066	7,408,885	69.10%			7,408,885	69.10%
369.UG Services - Underground	6,409,742	2,490,208	38.85%			2,490,208	38.85%
370.00 Meters	10,126,264	4,934,661	48.73%	(232,007)	-2.29%	4,702,654	46.44%
373.00 Street Lighting and Signal Systems	4,920,118	2,200,233	44.72%	7,352	0.15%	2,207,585	44.87%
Total Distribution Plant	$ 404,188,685	$ 209,247,005	51.77%	$ 12,712,394	3.15%	$ 221,959,399	54.91%
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	$ 5,086,394	$ 1,430,534	28.12%	$ 80,634	1.59%	$ 1,511,169	29.71%
392.C1 Transportation Equipment - Class 1	1,692,200	744,412	43.99%	3,740	0.22%	748,151	44.21%
392.C2 Transportation Equipment - Class 2	617,265	253,407	41.05%	8,511	1.38%	261,918	42.43%
392.C3 Transportation Equipment - Class 3	984,647	392,045	39.82%	7,664	0.78%	399,710	40.59%
392.C4 Transportation Equipment - Class 4	77,970	11,467	14.71%	80	0.10%	11,547	14.81%
392.C5 Transportation Equipment - Class 5	1,385,458	1,077,977	77.81%			1,077,977	77.81%
392.C6 Transportation Equipment - Class 6	20,070	7,981	39.77%	(1,197)	-5.96%	6,784	33.80%
392.C7 Transportation Equipment - Class 7	511,384	111,800	21.86%	(27,547)	-5.39%	84,252	16.48%
392.C8 Transportation Equipment - Class 8	6,907,249	4,893,609	70.85%			4,893,609	70.85%
392.C9 Transportation Equipment - Class 9	1,484,248	428,287	28.86%	(64,243)	-4.33%	364,044	24.53%
396.00 Power Operated Equipment	3,036,519	1,344,026	44.26%	(122,916)	-4.05%	1,221,110	40.21%
Total Depreciable	$ 21,803,404	$ 10,695,543	49.05%	$ (115,273)	-0.53%	$ 10,580,270	48.53%

UNS ELECTRIC, INC.
Depreciation Reserve Components
Redistributed Reserve
December 31, 2013

Statement D

	Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
	A	B	C	D=C/B	E	F=E/B	I=C+E+G	J=I/B
	Amortizable							
391.10	Office Furniture and Equipment	$ 1,791,213	$ 1,013,840	56.60%	$ -		$ 1,013,840	56.60%
391.20	Computer Equipment - PCs	1,111,667	438,178	39.42%			438,178	39.42%
393.00	Stores Equipment	347,815	232,696	66.90%			232,696	66.90%
394.00	Tools, Shop and Garage Equipment	2,624,550	2,008,709	76.54%			2,008,709	76.54%
395.00	Laboratory Equipment	1,933,101	1,219,122	63.07%			1,219,122	63.07%
397.CE	Communication Equipment	4,612,973	1,926,935	41.77%			1,926,935	41.77%
397.EM	Comm. Equip. - Energy Mgmt. System	1,192,687	134,439	11.27%			134,439	11.27%
398.00	Miscellaneous Equipment	127,465	49,039	38.47%			49,039	38.47%
	Total Amortizable	$ 13,741,471	$ 7,022,958	51.11%	$ -		$ 7,022,958	51.11%
	Total General Plant	$ 35,544,875	$ 17,718,501	49.85%	$ (115,273)	-0.32%	$ 17,603,228	49.52%
	TOTAL UTILITY	$ 654,340,590	$ 274,202,918	41.91%	$ 13,566,271	2.07%	$ 287,769,189	43.98%
	OTHER PRODUCTION							
	Black Mountain							
341.00	Structures and Improvements	$ 2,545,878	$ 327,919	12.88%	$ 27,044	1.06%	$ 354,962	13.94%
342.00	Fuel Holders, Producers and Accessories	337,317	43,495	12.89%	2,697	0.80%	46,192	13.69%
343.00	Prime Movers	5,884	634	10.77%	39	0.67%	673	11.44%
344.00	Generators	38,465,970	4,952,805	12.88%	336,369	0.87%	5,289,175	13.75%
345.00	Accessory Electric Equipment	9,194,049	1,145,510	12.46%	71,022	0.77%	1,216,531	13.23%
346.00	Miscellaneous Power Plant Equipment	10,827,001	1,361,453	12.57%	84,472	0.78%	1,445,926	13.35%
	Total Black Mountain	$ 61,376,099	$ 7,831,816	12.76%	$ 521,643	0.85%	$ 8,353,459	13.61%
	Enviromental							
341.00	Structures and Improvements	$ 1,580,293	$ 203,411	12.87%	$ 19,324	1.22%	$ 222,735	14.09%
342.00	Fuel Holders, Producers and Accessories							
343.00	Prime Movers							
344.00	Generators	6,884,651	887,744	12.89%	84,336	1.22%	972,080	14.12%
345.00	Accessory Electric Equipment							
346.00	Miscellaneous Power Plant Equipment	14,610	1,884	12.89%	179	1.22%	2,063	14.12%
	Total Enviromental	$ 8,479,554	$ 1,093,039	12.89%	$ 103,839	1.22%	$ 1,196,878	14.11%

UNS ELECTRIC, INC.
Depreciation Reserve Components
Redistributed Reserve
December 31, 2013

Statement D

Account Description		Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A		B	C	D=C/B	E	F=E/B	I=C+E+G	J=I/B
Non-Enviromental								
341.00	Structures and Improvements	$ 965,585	$ 124,508	12.89%	$ 7,719	0.80%	$ 132,227	13.69%
342.00	Fuel Holders, Producers and Accessories	337,317	43,495	12.89%	2,697	0.80%	46,192	13.69%
343.00	Prime Movers	5,884	634	10.77%	39	0.67%	673	11.44%
344.00	Generators	31,581,319	4,065,061	12.87%	252,034	0.80%	4,317,095	13.67%
345.00	Accessory Electric Equipment	9,194,049	1,145,510	12.46%	71,022	0.77%	1,216,531	13.23%
346.00	Miscellaneous Power Plant Equipment	10,812,391	1,359,570	12.57%	84,293	0.78%	1,443,863	13.35%
Total Non-Enviromental		$ 52,896,545	$ 6,738,777	12.74%	$ 417,804	0.79%	$ 7,156,582	13.53%
Valencia								
341.00	Structures and Improvements	$ 2,023,551	$ 422,709	20.89%	$ 58,236	2.88%	$ 480,945	23.77%
342.00	Fuel Holders, Producers and Accessories	874,375	233,857	26.75%	20,579	2.35%	254,436	29.10%
343.00	Prime Movers	13,468,397	3,851,639	28.60%	515,747	3.83%	4,367,386	32.43%
344.00	Generators	6,706,754	1,462,544	21.81%	135,099	2.01%	1,597,644	23.82%
345.00	Accessory Electric Equipment	2,918,385	762,165	26.12%	86,907	2.98%	849,072	29.09%
346.00	Miscellaneous Power Plant Equipment	1,885,668	333,627	17.69%	33,507	1.78%	367,135	19.47%
Total Valencia		$ 27,877,130	$ 7,066,541	25.35%	$ 850,076	3.05%	$ 7,916,617	28.40%
Enviromental								
341.00	Structures and Improvements	$ 178,908	$ 31,692	17.71%	$ 7,384	4.13%	$ 39,076	21.84%
342.00	Fuel Holders, Producers and Accessories							
343.00	Prime Movers	61,731	10,935	17.71%	2,548	4.13%	13,483	21.84%
344.00	Generators	18,506	3,278	17.71%	764	4.13%	4,042	21.84%
345.00	Accessory Electric Equipment	9,551	1,692	17.71%	394	4.13%	2,086	21.84%
346.00	Miscellaneous Power Plant Equipment	27,463	4,865	17.71%	1,134	4.13%	5,998	21.84%
Total Enviromental		$ 296,159	$ 52,462	17.71%	$ 12,224	4.13%	$ 64,686	21.84%
Non-Enviromental								
341.00	Structures and Improvements	$ 1,844,643	$ 391,017	21.20%	$ 50,852	2.76%	$ 441,868	23.95%
342.00	Fuel Holders, Producers and Accessories	874,375	233,857	26.75%	20,579	2.35%	254,436	29.10%
343.00	Prime Movers	13,406,666	3,840,703	28.65%	513,199	3.83%	4,353,902	32.48%
344.00	Generators	6,688,248	1,459,266	21.82%	134,335	2.01%	1,593,602	23.83%
345.00	Accessory Electric Equipment	2,908,834	760,473	26.14%	86,513	2.97%	846,985	29.12%
346.00	Miscellaneous Power Plant Equipment	1,858,205	328,762	17.69%	32,374	1.74%	361,136	19.43%
Total Non-Enviromental		$ 27,580,971	$ 7,014,078	25.43%	$ 837,852	3.04%	$ 7,851,930	28.47%

UNS ELECTRIC, INC.
Depreciation Reserve Components
Redistributed Reserve
December 31, 2013

Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	I=C+E+G	J=I/B
La Senita							
341.00 Structures and Improvements	$ 28,908	$ 2,683	9.28%	$ 378	1.31%	$ 3,061	10.59%
342.00 Fuel Holders, Producers and Accessories							
343.00 Prime Movers							
344.00 Generators	4,972,083	461,412	9.28%	65,059	1.31%	526,471	10.59%
345.00 Accessory Electric Equipment							
346.00 Miscellaneous Power Plant Equipment							
Total La Senita	$ 5,000,991	$ 464,095	9.28%	$ 65,437	1.31%	$ 529,532	10.59%
Rio Rico							
341.00 Structures and Improvements	$ -	$ -		$ -		$ -	
342.00 Fuel Holders, Producers and Accessories							
343.00 Prime Movers							
344.00 Generators	13,936,461	374,797	2.69%	60,717	0.44%	435,514	3.13%
345.00 Accessory Electric Equipment							
346.00 Miscellaneous Power Plant Equipment							
Total Rio Rico	$ 13,936,461	$ 374,797	2.69%	$ 60,717	0.44%	$ 435,514	3.13%

UNS ELECTRIC, INC.
Average Net Salvage

Statement E

Account Description		Plant Investment			Salvage Rate		Net Salvage			Average
		Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A		B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
INTANGIBLE PLANT										
Depreciable										
303.WP	Misc.Intangible - WAPA Switchboard	$ 3,466,688	$ -	$ 3,466,688			$ -	$ -	$ -	
	Total Depreciable	$ 3,466,688	$ -	$ 3,466,688			$ -	$ -	$ -	
Amortizable										
303.OT	Miscellaneous Intangible Plant	$ 4,219,099	$ 2,094,492	$ 2,124,607			$ -	$ -	$ -	
303.WO	Misc. Intangible - WAPA Fiber Optic	1,685,000		1,685,000						
303.PC	Misc.Intangible Plant - PC Software	2,146,709	1,543,417	603,292						
	Total Amortizable	$ 8,050,808	$ 3,637,909	$ 4,412,899			$ -	$ -	$ -	
	Total Intangible Plant	$ 11,517,496	$ 3,637,909	$ 7,879,587			$ -	$ -	$ -	
OTHER PRODUCTION										
341.00	Structures and Improvements	$ 4,822,743	$ 224,406	$ 4,598,337		-9.1%	$ -	$ (418,084)	$ (418,084)	-8.7%
342.00	Fuel Holders, Producers and Accessories	1,212,023	331	1,211,692		-8.1%		(97,859)	(97,859)	-8.1%
343.00	Prime Movers	16,223,937	2,749,656	13,474,281	0.4%	-8.9%	10,999	(1,194,535)	(1,183,536)	-7.3%
344.00	Generators	64,175,991	94,723	64,081,268	3.1%	-9.6%	2,976	(6,163,732)	(6,160,756)	-9.6%
345.00	Accessory Electric Equipment	12,402,188	289,754	12,112,434		-6.8%		(828,234)	(828,234)	-6.7%
346.00	Miscellaneous Power Plant Equipment	12,752,970	40,301	12,712,669		-6.6%		(841,677)	(841,677)	-6.6%
	Total Other Production Plant	$ 111,589,852	$ 3,399,171	$ 108,190,681	0.4%	-8.8%	$ 13,975	$ (9,544,120)	$ (9,530,146)	-8.5%
TRANSMISSION PLANT										
350.RW	Rights of Way	$ 360,403	$ 587	$ 359,816		-10.0%	$ -	$ (35,982)	$ (35,982)	-10.0%
352.00	Structures and Improvements	920,764	3,118	917,646		-10.0%		(91,765)	(91,765)	-10.0%
353.00	Station Equipment	33,228,527	1,976,368	31,252,159	11.6%	10.0%	229,259	3,125,216	3,354,475	10.1%
354.00	Towers and Fixtures	521,825	436,094	85,731		-10.0%		(8,573)	(8,573)	-1.6%
355.00	Poles and Fixtures	52,284,966	3,600,968	48,683,998	11.1%	10.0%	399,707	4,868,400	5,268,107	10.1%
356.00	Overhead Conductors and Devices	17,795,217	820,719	16,974,498	7.8%	-10.0%	64,016	(1,697,450)	(1,633,434)	-9.2%
358.00	Underground Conductors and Devices	29,815		29,815		-5.0%		(1,491)	(1,491)	-5.0%
359.00	Roads and Trails	233,099		233,099		-10.0%		(23,310)	(23,310)	-10.0%
	Total Transmission Plant	$ 105,374,616	$ 6,837,854	$ 98,536,762	10.1%	6.2%	$ 692,982	$ 6,135,046	$ 6,828,028	6.5%
DISTRIBUTION PLANT										
360.RW	Rights of Way	$ 143,806	$ -	$ 143,806			$ -	$ -	$ -	
361.00	Structures and Improvements	6,722,382	27,958	6,694,424	-2.6%		(727)		(727)	
362.00	Station Equipment	64,789,985	2,409,602	62,380,383	-7.6%	-10.0%	(183,130)	(6,238,038)	(6,421,168)	-9.9%
364.00	Poles, Towers and Fixtures	95,277,888	2,031,471	93,246,417	10.0%		203,147		203,147	0.2%
365.00	Overhead Conductors and Devices	73,919,124	2,399,863	71,519,261						
366.00	Underground Conduit	20,945,754	250,069	20,695,685	28.2%		70,519		70,519	0.3%

UNS ELECTRIC, INC.
Average Net Salvage

Statement E

	Account Description	Plant Investment: Additions	Plant Investment: Retirements	Plant Investment: Survivors	Salvage Rate: Realized	Salvage Rate: Future	Net Salvage: Realized	Net Salvage: Future	Net Salvage: Total	Average Rate
	A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
367.00	Underground Conductors and Devices	44,507,866	900,410	43,607,456	8.9%		80,136		80,136	0.2%
368.OH	Line Transformers - Overhead	52,284,763	1,297,828	50,986,935	-50.8%	-30.0%	(659,297)	(15,296,081)	(15,955,377)	-30.5%
368.UG	Line Transformers - Underground	23,131,776	395,648	22,736,128	-50.8%	-30.0%	(200,989)	(6,820,838)	(7,021,828)	-30.4%
369.OH	Services - Overhead	10,744,137	22,071	10,722,066						
369.UG	Services - Underground	6,428,218	18,476	6,409,742						
370.00	Meters	15,427,644	5,301,380	10,126,264	5.3%	5.0%	280,973	506,313	787,286	5.1%
373.00	Street Lighting and Signal Systems	5,208,331	288,213	4,920,118	2.4%		6,917		6,917	0.1%
	Total Distribution Plant	$ 419,531,674	$ 15,342,989	$ 404,188,685	-2.6%	-6.9%	$ (402,449)	$ (27,848,644)	$ (28,251,093)	-6.7%
	GENERAL PLANT									
	Depreciable									
390.00	Structures and Improvements	$ 5,139,391	$ 52,997	$ 5,086,394	10.2%	-5.0%	$ 5,406	$ (254,320)	$ (248,914)	-4.8%
392.C1	Transportation Equipment - Class 1	2,450,601	758,401	1,692,200	1.0%		7,584		7,584	0.3%
392.C2	Transportation Equipment - Class 2	1,528,901	911,636	617,265	3.0%		27,349		27,349	1.8%
392.C3	Transportation Equipment - Class 3	2,862,513	1,877,866	984,647	1.6%		30,046		30,046	1.0%
392.C4	Transportation Equipment - Class 4	4,008,117	3,930,147	77,970	0.1%		3,930		3,930	0.1%
392.C5	Transportation Equipment - Class 5	1,612,624	227,166	1,385,458						
392.C6	Transportation Equipment - Class 6	20,070		20,070		15.0%		3,011	3,011	15.0%
392.C7	Transportation Equipment - Class 7	598,977	87,593	511,384		15.0%		76,708	76,708	12.8%
392.C8	Transportation Equipment - Class 8	7,779,628	872,379	6,907,249						
392.C9	Transportation Equipment - Class 9	1,484,248		1,484,248		15.0%		222,637	222,637	15.0%
396.00	Power Operated Equipment	3,175,089	138,570	3,036,519	-52.7%	5.0%	(73,026)	151,826	78,800	2.5%
	Total Depreciable	$ 30,660,159	$ 8,856,755	$ 21,803,404		0.9%	$ 1,288	$ 199,862	$ 201,150	0.7%
	Amortizable									
391.10	Office Furniture and Equipment	$ 5,885,472	$ 4,094,259	$ 1,791,213			$ -	$ -	$ -	
391.20	Computer Equipment - PCs	2,704,869	1,593,202	1,111,667						
393.00	Stores Equipment	370,331	22,516	347,815						
394.00	Tools, Shop and Garage Equipment	3,203,403	578,853	2,624,550						
395.00	Laboratory Equipment	1,994,046	60,945	1,933,101						
397.CE	Communication Equipment	4,790,044	177,071	4,612,973						
397.EM	Comm. Equip. - Energy Mgmt. System	1,192,687		1,192,687						
398.00	Miscellaneous Equipment	228,666	101,201	127,465						
	Total Amortizable	$ 20,369,518	$ 6,628,047	$ 13,741,471			$ -	$ -	$ -	
	Total General Plant	$ 51,029,677	$ 15,484,802	$ 35,544,875		0.6%	$ 1,288	$ 199,862	$ 201,150	0.4%
	TOTAL UTILITY	$ 699,043,315	$ 44,702,725	$ 654,340,590	0.7%	-4.7%	$ 305,796	$ (31,057,857)	$ (30,752,061)	-4.4%

UNS ELECTRIC, INC.
Average Net Salvage

Statement E

Account Description	Plant Investment: Additions	Plant Investment: Retirements	Plant Investment: Survivors	Salvage Rate: Realized	Salvage Rate: Future	Net Salvage: Realized	Net Salvage: Future	Net Salvage: Total	Average Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
OTHER PRODUCTION									
<u>Black Mountain</u>									
341.00 Structures and Improvements	$ 2,545,878	$ -	$ 2,545,878		-8.2%	$ -	$ (209,994)	$ (209,994)	-8.2%
342.00 Fuel Holders, Producers and Accessories	337,317		337,317		-6.2%		(20,914)	(20,914)	-6.2%
343.00 Prime Movers	5,884		5,884		-6.2%		(365)	(365)	-6.2%
344.00 Generators	38,497,370	31,400	38,465,970		-6.8%		(2,612,084)	(2,612,084)	-6.8%
345.00 Accessory Electric Equipment	9,194,049		9,194,049		-6.2%		(570,031)	(570,031)	-6.2%
346.00 Miscellaneous Power Plant Equipment	10,827,001		10,827,001		-6.2%		(671,756)	(671,756)	-6.2%
Total Black Mountain	$ 61,407,499	$ 31,400	$ 61,376,099		-6.7%	$ -	$ (4,085,143)	$ (4,085,143)	-6.7%
<u>Enviromental</u>									
341.00 Structures and Improvements	$ 1,580,293	$ -	$ 1,580,293		-9.5%	$ -	$ (150,128)	$ (150,128)	-9.5%
342.00 Fuel Holders, Producers and Accessories									
343.00 Prime Movers									
344.00 Generators	6,884,651		6,884,651		-9.5%		(654,042)	(654,042)	-9.5%
345.00 Accessory Electric Equipment									
346.00 Miscellaneous Power Plant Equipment	14,610		14,610		-9.5%		(1,388)	(1,388)	-9.5%
Total Enviromental	$ 8,479,554	$ -	$ 8,479,554		-9.5%	$ -	$ (805,558)	$ (805,558)	-9.5%
<u>Non-Enviromental</u>									
341.00 Structures and Improvements	$ 965,585	$ -	$ 965,585		-6.2%	$ -	$ (59,866)	$ (59,866)	-6.2%
342.00 Fuel Holders, Producers and Accessories	337,317		337,317		-6.2%		(20,914)	(20,914)	-6.2%
343.00 Prime Movers	5,884		5,884		-6.2%		(365)	(365)	-6.2%
344.00 Generators	31,612,719	31,400	31,581,319		-6.2%		(1,958,042)	(1,958,042)	-6.2%
345.00 Accessory Electric Equipment	9,194,049		9,194,049		-6.2%		(570,031)	(570,031)	-6.2%
346.00 Miscellaneous Power Plant Equipment	10,812,391		10,812,391		-6.2%		(670,368)	(670,368)	-6.2%
Total Non-Enviromental	$ 52,927,945	$ 31,400	$ 52,896,545		-6.2%	$ -	$ (3,279,586)	$ (3,279,586)	-6.2%
<u>Valencia</u>									
341.00 Structures and Improvements	$ 2,247,957	$ 224,406	$ 2,023,551		-10.1%	$ -	$ (204,014)	$ (204,014)	-9.1%
342.00 Fuel Holders, Producers and Accessories	874,706	331	874,375		-8.8%		(76,945)	(76,945)	-8.8%
343.00 Prime Movers	16,218,053	2,749,656	13,468,397	0.4%	-8.9%	10,999	(1,194,170)	(1,183,171)	-7.3%
344.00 Generators	6,770,077	63,323	6,706,754	4.7%	-8.8%	2,976	(592,878)	(589,902)	-8.7%
345.00 Accessory Electric Equipment	3,208,139	289,754	2,918,385		-8.8%		(258,203)	(258,203)	-8.0%
346.00 Miscellaneous Power Plant Equipment	1,925,969	40,301	1,885,668		-9.0%		(169,921)	(169,921)	-8.8%
Total Valencia	$ 31,244,901	$ 3,367,771	$ 27,877,130	0.4%	-9.0%	$ 13,975	$ (2,496,130)	$ (2,482,156)	-7.9%
<u>Enviromental</u>									
341.00 Structures and Improvements	$ 178,908	$ -	$ 178,908		-23.3%	$ -	$ (41,686)	$ (41,686)	-23.3%
342.00 Fuel Holders, Producers and Accessories									
343.00 Prime Movers	61,731		61,731		-23.3%		(14,383)	(14,383)	-23.3%
344.00 Generators	18,506		18,506		-23.3%		(4,312)	(4,312)	-23.3%
345.00 Accessory Electric Equipment	9,551		9,551		-23.3%		(2,225)	(2,225)	-23.3%
346.00 Miscellaneous Power Plant Equipment	27,463		27,463		-23.3%		(6,399)	(6,399)	-23.3%
Total Enviromental	$ 296,159	$ -	$ 296,159		-23.3%	$ -	$ (69,005)	$ (69,005)	-23.3%

UNS ELECTRIC, INC.
Average Net Salvage

Statement E

Account Description		Plant Investment			Salvage Rate		Net Salvage			Average
		Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A		B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Non-Enviromental										
341.00	Structures and Improvements	$ 2,069,049	$ 224,406	$ 1,844,643		-8.8%	$ -	$ (162,329)	$ (162,329)	-7.8%
342.00	Fuel Holders, Producers and Accessories	874,706	331	874,375		-8.8%		(76,945)	(76,945)	-8.8%
343.00	Prime Movers	16,156,322	2,749,656	13,406,666	0.4%	-8.8%	10,999	(1,179,787)	(1,168,788)	-7.2%
344.00	Generators	6,751,571	63,323	6,688,248	4.7%	-8.8%	2,976	(588,566)	(585,590)	-8.7%
345.00	Accessory Electric Equipment	3,198,588	289,754	2,908,834		-8.8%		(255,977)	(255,977)	-8.0%
346.00	Miscellaneous Power Plant Equipment	1,898,506	40,301	1,858,205		-8.8%		(163,522)	(163,522)	-8.6%
	Total Non-Enviromental	$ 30,948,742	$ 3,367,771	$ 27,580,971	0.4%	-8.8%	$ 13,975	$ (2,427,125)	$ (2,413,151)	-7.8%
La Senita										
341.00	Structures and Improvements	$ 28,908	$ -	$ 28,908		-14.1%	$ -	$ (4,076)	$ (4,076)	-14.1%
342.00	Fuel Holders, Producers and Accessories									
343.00	Prime Movers									
344.00	Generators	4,972,083		4,972,083		-14.1%		(701,064)	(701,064)	-14.1%
345.00	Accessory Electric Equipment									
346.00	Miscellaneous Power Plant Equipment									
	Total La Senita	$ 5,000,991	$ -	$ 5,000,991		-14.1%	$ -	$ (705,140)	$ (705,140)	-14.1%
Rio Rico										
341.00	Structures and Improvements	$ -	$ -	$ -			$ -	$ -	$ -	
342.00	Fuel Holders, Producers and Accessories									
343.00	Prime Movers									
344.00	Generators	13,936,461		13,936,461		-16.2%		(2,257,707)	(2,257,707)	-16.2%
345.00	Accessory Electric Equipment									
346.00	Miscellaneous Power Plant Equipment									
	Total Rio Rico	$ 13,936,461	$ -	$ 13,936,461		-16.2%	$ -	$ (2,257,707)	$ (2,257,707)	-16.2%

UNS ELECTRIC, INC.
Future Net Salvage
Other Production

Statement F

Account Description	12/31/13 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
OTHER PRODUCTION									
Black Mountain									
Enviromental									
341.00 Structures and Improvements	$ 1,580,293	$ 156,225	$ 1,424,068		-10.6%	$ -	$ (150,293)	$ (150,293)	-9.5%
342.00 Fuel Holders, Producers and Accessorie									
343.00 Prime Movers									
344.00 Generators	6,884,651	680,613	6,204,038		-10.6%		(654,761)	(654,761)	-9.5%
345.00 Accessory Electric Equipment									
346.00 Miscellaneous Power Plant Equipment	14,610	1,444	13,166		-10.6%		(1,389)	(1,389)	-9.5%
Total Enviromental	$ 8,479,554	$ 838,283	$ 7,641,271		-10.6%	$ -	$ (806,443)	$ (806,443)	-9.5%
Non-Enviromental									
341.00 Structures and Improvements	$ 965,585	$ 95,457	$ 870,128		-6.8%	$ -	$ (59,544)	$ (59,544)	-6.2%
342.00 Fuel Holders, Producers and Accessorie	337,317	33,347	303,970		-6.8%		(20,801)	(20,801)	-6.2%
343.00 Prime Movers	5,884	580	5,304		-6.8%		(363)	(363)	-6.2%
344.00 Generators	31,581,319	3,122,056	28,459,263		-6.8%		(1,947,496)	(1,947,496)	-6.2%
345.00 Accessory Electric Equipment	9,194,049	908,469	8,285,580		-6.8%		(566,991)	(566,991)	-6.2%
346.00 Miscellaneous Power Plant Equipment	10,812,391	1,068,532	9,743,859		-6.8%		(666,782)	(666,782)	-6.2%
Total Non-Enviromental	$ 52,896,545	$ 5,228,441	$ 47,668,104		-6.8%	$ -	$ (3,261,977)	$ (3,261,977)	-6.2%
Valencia									
Enviromental									
341.00 Structures and Improvements	$ 178,908	$ 16,865	$ 162,043		-25.7%	$ -	$ (41,625)	$ (41,625)	-23.3%
342.00 Fuel Holders, Producers and Accessorie									
343.00 Prime Movers	61,731	5,819	55,912		-25.7%		(14,362)	(14,362)	-23.3%
344.00 Generators	18,506	1,745	16,761		-25.7%		(4,306)	(4,306)	-23.3%
345.00 Accessory Electric Equipment	9,551	900	8,651		-25.7%		(2,222)	(2,222)	-23.3%
346.00 Miscellaneous Power Plant Equipment	27,463	2,589	24,874		-25.7%		(6,390)	(6,390)	-23.3%
Total Enviromental	$ 296,159	$ 27,918	$ 268,241		-25.7%	$ -	$ (68,904)	$ (68,904)	-23.3%
Non-Enviromental									
341.00 Structures and Improvements	$ 1,844,643	$ 175,191	$ 1,669,452		-9.8%	$ -	$ (162,847)	$ (162,847)	-8.8%
342.00 Fuel Holders, Producers and Accessorie	874,375	83,621	790,754		-9.8%		(77,134)	(77,134)	-8.8%
343.00 Prime Movers	13,406,666	1,292,754	12,113,912		-9.8%		(1,181,656)	(1,181,656)	-8.8%
344.00 Generators	6,688,248	634,810	6,053,438		-9.8%		(590,485)	(590,485)	-8.8%
345.00 Accessory Electric Equipment	2,908,834	279,006	2,629,828		-9.8%		(256,528)	(256,528)	-8.8%
346.00 Miscellaneous Power Plant Equipment	1,858,205	175,359	1,682,846		-9.8%		(164,154)	(164,154)	-8.8%
Total Non-Enviromental	$ 27,580,971	$ 2,640,741	$ 24,940,230		-9.8%	$ -	$ (2,432,805)	$ (2,432,805)	-8.8%

UNS ELECTRIC, INC.
Future Net Salvage
Other Production

Statement F

Account Description	12/31/13 Plant Investment	Future Retirements		Net Salvage Rate		Future Net Salvage			Future Rate
		Interim	Final	Interim	Final	Interim	Final	Total	
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
La Senita									
341.00 Structures and Improvements	$ 28,908	1,600	$ 27,308		-14.9%	$ -	$ (4,072)	$ (4,072)	-14.1%
342.00 Fuel Holders, Producers and Accessori									
343.00 Prime Movers									
344.00 Generators	4,972,083	275,185	4,696,898		-14.9%		(700,445)	(700,445)	-14.1%
345.00 Accessory Electric Equipment									
346.00 Miscellaneous Power Plant Equipment									
Total La Senita	$ 5,000,991	$ 276,785	$ 4,724,206		-14.9%	$ -	$ (704,517)	$ (704,517)	-14.1%
Rio Rico									
341.00 Structures and Improvements	$ -		$ -			$ -	$ -	$ -	
342.00 Fuel Holders, Producers and Accessori									
343.00 Prime Movers									
344.00 Generators	13,936,461	872,121	13,064,340		-17.3%		(2,259,114)	(2,259,114)	-16.2%
345.00 Accessory Electric Equipment									
346.00 Miscellaneous Power Plant Equipment									
Total Rio Rico	$ 13,936,461	$ 872,121	$ 13,064,340		-17.3%	$ -	$ (2,259,114)	$ (2,259,114)	-16.2%

UNS ELECTRIC, INC.
Current and Proposed Parameters
Vintage Group Procedure

Statement G

Account Description	Current P-Life/ AYFR	Current Curve Shape	Current BG ASL	Current Rem. Life	Current Avg. Sal.	Current Fut. Sal.	Proposed P-Life/ AYFR	Proposed Curve Shape	Proposed VG ASL	Proposed Rem. Life	Proposed Avg. Sal.	Proposed Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
INTANGIBLE PLANT												
Depreciable												
303.WP Misc.Intangible - WAPA Switchboard	32.00	R1	32.00	28.02			32.00	R1	32.51	24.55		
Total Depreciable			32.00	28.02					32.51	24.55		0.9
Amortizable												
303.OT Miscellaneous Intangible Plant	15.00	SQ	15.00	5.81			15.00	SQ	15.00	1.00		
303.WO Misc. Intangible - WAPA Fiber Optic	23.00	SQ	23.00	17.50			23.00	SQ	23.00	12.50		
303.PC Misc.Intangible Plant - PC Software	5.00	SQ	5.00	2.48			5.00	SQ	5.00	2.36		
Total Amortizable			13.15	7.16					13.15	4.00		
Total Intangible Plant									17.82	8.96		
OTHER PRODUCTION												
341.00 Structures and Improvements			42.46	38.60					42.96	36.56	-8.7	-9.1
342.00 Fuel Holders, Producers and Accessories			39.42	33.35					45.73	36.24	-8.1	-8.1
343.00 Prime Movers			40.00	28.50					48.15	35.67	-7.3	-8.9
344.00 Generators			30.32	20.81					35.31	31.68	-9.6	-9.6
345.00 Accessory Electric Equipment			39.10	36.30					43.31	37.11	-6.7	-6.8
346.00 Miscellaneous Power Plant Equipment			38.00	37.07					42.39	37.25	-6.6	-6.6
Total Other Production Plant			33.45	25.49					38.53	33.44	-8.5	-8.8
TRANSMISSION PLANT												
350.RW Rights of Way	50.00	SQ	50.00	28.60			60.00	R5	60.13	48.94	-10.0	-10.0
352.00 Structures and Improvements	33.00	R3	33.00	21.76			55.00	R5	55.02	44.88	-10.0	-10.0
353.00 Station Equipment	32.00	R1	32.00	20.52			55.00	R1	55.85	45.81	10.1	10.0
354.00 Towers and Fixtures	20.00	L0	20.00	14.58			60.00	R4	69.76	15.96	-1.6	-10.0
355.00 Poles and Fixtures	25.00	S5	25.00	15.76	-9.9	-10.0	36.00	L0.5	36.61	32.53	10.1	10.0
356.00 Overhead Conductors and Devices	38.00	L3	38.00	24.76			45.00	S2	45.51	30.24	-9.2	-10.0
358.00 Underground Conductors and Devices	50.00	R4	50.00	47.50	-5.0	-5.0	50.00	R4	50.00	42.84	-5.0	-5.0
359.00 Roads and Trails	50.00	SQ	50.00	32.18			60.00	R5	60.47	34.03	-10.0	-10.0
Total Transmission Plant			28.85	18.40					43.02	35.53	6.5	6.2

UNS ELECTRIC, INC.
Current and Proposed Parameters
Vintage Group Procedure

Statement G

		Current Parameters						Proposed Parameters					
	Account Description	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
	A	B	C	D	E	F	G	H	I	J	K	L	M
DISTRIBUTION PLANT													
360.RW	Rights of Way	50.00	SQ	50.00	33.03			60.00	R5	60.06	39.27		
361.00	Structures and Improvements	34.00	R4	34.00	26.11	0.1		55.00	R1	55.64	45.86		
362.00	Station Equipment	25.00	S4	25.00	13.57			56.00	L1.5	56.35	46.65	-9.9	-10.0
364.00	Poles, Towers and Fixtures	27.00	S4	27.00	13.80	-9.7	-10.0	50.00	R2.5	50.74	32.21	0.2	
365.00	Overhead Conductors and Devices	27.00	S3	27.00	15.12	-9.9	-10.0	55.00	R3	55.14	40.29		
366.00	Underground Conduit	28.00	S2	28.00	18.66	-5.0	-5.0	65.00	R4	64.98	52.56	0.3	
367.00	Underground Conductors and Devices	23.00	S3	23.00	15.52	-0.5		47.00	R4	47.12	34.99	0.2	
368.OH	Line Transformers - Overhead	23.00	S4	23.00	13.82	-5.6	-5.0	47.00	R3	47.23	33.99	-30.5	-30.0
368.UG	Line Transformers - Underground	23.00	S4	23.00	13.82	-5.6	-5.0	47.00	R3	47.01	38.23	-30.4	-30.0
369.OH	Services - Overhead	27.00	R5	27.00	13.82			45.00	S3	45.35	29.21		
369.UG	Services - Underground	27.00	R5	27.00	17.43			60.00	S3	60.02	48.01		
370.00	Meters	34.00	R3	34.00	25.56	-3.9	-5.0	20.00	L1	20.16	15.10	5.1	5.0
373.00	Street Lighting and Signal Systems	25.00	S4	25.00	14.77			50.00	L1.5	50.45	38.83	0.1	
	Total Distribution Plant			25.64	14.87					49.81	36.53	-6.7	-6.9
GENERAL PLANT													
	Depreciable												
390.00	Structures and Improvements	38.00	R2	38.00	27.19			40.00	R4	40.16	30.56	-4.8	-5.0
392.C1	Transportation Equipment - Class 1	8.00	L1.5	8.00	5.76	4.0	10.0	10.00	L2	10.19	6.38	0.3	
392.C2	Transportation Equipment - Class 2	6.00	L2	6.00	3.65	7.7	10.0	10.00	L2	10.26	6.68	1.8	
392.C3	Transportation Equipment - Class 3	5.00	S5	5.00	2.41	5.2	10.0	9.00	L1	9.19	6.08	1.0	
392.C4	Transportation Equipment - Class 4	5.00	S5	5.00	2.41	5.2	10.0	12.00	L3	12.00	10.50	0.1	
392.C5	Transportation Equipment - Class 5	8.00	S4	8.00	5.62	10.0	10.0	8.00	R5	8.09	2.74		
392.C6	Transportation Equipment - Class 6	8.00	S4	8.00	5.62	10.0	10.0	15.00	L2	15.06	9.97	15.0	15.0
392.C7	Transportation Equipment - Class 7	8.00	S4	8.00	5.62	10.0	10.0	14.00	L1.5	14.10	11.48	12.8	15.0
392.C8	Transportation Equipment - Class 8	8.00	S4	8.00	5.62	10.0	10.0	9.00	R4	9.25	3.68		
392.C9	Transportation Equipment - Class 9	8.00	S4	8.00	5.62	10.0	10.0	20.00	S2	20.02	15.11	15.0	15.0
396.00	Power Operated Equipment	15.00	S5	15.00	9.00			15.00	L2	16.64	10.38	2.5	5.0
	Total Depreciable			10.13	6.88					12.99	7.57	0.7	0.9

UNS ELECTRIC, INC.
Current and Proposed Parameters
Vintage Group Procedure

Statement G

Account Description	Current Parameters						Proposed Parameters					
	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Amortizable												
391.10 Office Furniture and Equipment	21.00	SQ	21.00	8.70			21.00	SQ	21.00	9.11		
391.20 Computer Equipment - PCs	5.00	SQ	5.00	2.89			5.00	SQ	5.00	3.03		
393.00 Stores Equipment	33.00	SQ	33.00	12.68			15.00	SQ	15.00	8.57		
394.00 Tools, Shop and Garage Equipment	29.00	SQ	29.00	15.69			15.00	SQ	15.00	6.96		
395.00 Laboratory Equipment	40.00	SQ	40.00	28.70			15.00	SQ	15.00	8.46		
397.CE Communication Equipment	23.00	SQ	23.00	16.10			15.00	SQ	15.00	9.96		
397.EM Comm. Equip. - Energy Mgmt. System	23.00	SQ	23.00	16.10			15.00	SQ	15.00	13.31		
398.00 Miscellaneous Equipment	18.00	SQ	18.00	6.22			15.00	SQ	15.00	10.26		
Total Amortizable			19.18	11.77					13.34	7.93		
Total General Plant									13.12	7.71	0.4	0.6
TOTAL UTILITY									39.99	30.34	-4.4	-4.7
OTHER PRODUCTION												
Black Mountain												
341.00 Structures and Improvements	2048	200-SC	38.00	37.55					42.50	37.52	-8.2	-8.2
342.00 Fuel Holders, Producers and Accessories	2048	200-SC	38.00	37.55					42.51	37.52	-6.2	-6.2
343.00 Prime Movers	2048	200-SC	38.00	37.55					41.61	37.53	-6.2	-6.2
344.00 Generators	2048	200-SC	38.00	37.55					42.50	37.52	-6.8	-6.8
345.00 Accessory Electric Equipment	2048	200-SC	38.00	37.55					42.32	37.52	-6.2	-6.2
346.00 Miscellaneous Power Plant Equipment	2048	200-SC	38.00	37.55					42.37	37.52	-6.2	-6.2
Total Black Mountain			38.00	37.55					42.45	37.52	-6.7	-6.7
Enviromental												
341.00 Structures and Improvements	2048	200-SC	38.00	37.55			2053	200-SC	42.50	37.52	-9.5	-9.5
342.00 Fuel Holders, Producers and Accessories	2048	200-SC	38.00	37.55								
343.00 Prime Movers												
344.00 Generators	2048	200-SC	38.00	37.55			2053	200-SC	42.51	37.52	-9.5	-9.5
345.00 Accessory Electric Equipment	2048	200-SC	38.00	37.55								
346.00 Miscellaneous Power Plant Equipment	2048	200-SC	38.00	37.55			2053	200-SC	42.51	37.52	-9.5	-9.5
Total Enviromental			38.00	37.55					42.51	37.52	-9.5	-9.5

UNS ELECTRIC, INC.
Current and Proposed Parameters
Vintage Group Procedure

Statement G

Account Description	Current Parameters P-Life/ AYFR	Current Parameters Curve Shape	Current Parameters BG ASL	Current Parameters Rem. Life	Current Parameters Avg. Sal.	Current Parameters Fut. Sal.	Proposed Parameters P-Life/ AYFR	Proposed Parameters Curve Shape	Proposed Parameters VG ASL	Proposed Parameters Rem. Life	Proposed Parameters Avg. Sal.	Proposed Parameters Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Non-Enviromental												
341.00 Structures and Improvements	2048	200-SC	38.00	37.55			2053	200-SC	42.51	37.52	-6.2	-6.2
342.00 Fuel Holders, Producers and Accessories	2048	200-SC	38.00	37.55			2053	200-SC	42.51	37.52	-6.2	-6.2
343.00 Prime Movers	2048	200-SC	38.00	37.55			2053	200-SC	41.61	37.53	-6.2	-6.2
344.00 Generators	2048	200-SC	38.00	37.55			2053	200-SC	42.50	37.52	-6.2	-6.2
345.00 Accessory Electric Equipment	2048	200-SC	38.00	37.55			2053	200-SC	42.32	37.52	-6.2	-6.2
346.00 Miscellaneous Power Plant Equipment	2048	200-SC	38.00	37.55			2053	200-SC	42.37	37.52	-6.2	-6.2
Total Non-Enviromental			38.00	37.55					42.44	37.52	-6.2	-6.2
Valencia												
341.00 Structures and Improvements	49.00	S6	49.00	40.31					44.04	35.70	-9.1	-10.1
342.00 Fuel Holders, Producers and Accessories	40.00	S4	40.00	31.64					47.11	35.69	-8.8	-8.8
343.00 Prime Movers	40.00	R3	40.00	28.50					48.15	35.67	-7.3	-8.9
344.00 Generators	43.00	S0	43.00	38.26					44.49	35.70	-8.7	-8.8
345.00 Accessory Electric Equipment	43.00	S6	43.00	31.86					46.74	35.68	-8.0	-8.8
346.00 Miscellaneous Power Plant Equipment	38.00	R1	38.00	34.33					42.53	35.71	-8.8	-9.0
Total Valencia			41.40	32.36					46.33	35.68	-7.9	-9.0
Enviromental												
341.00 Structures and Improvements	49.00	S6	49.00	40.31			2051	200-SC	42.54	35.71	-23.3	-23.3
342.00 Fuel Holders, Producers and Accessories												
343.00 Prime Movers	40.00	R3	40.00	28.50	0.1		2051	200-SC	42.54	35.71	-23.3	-23.3
344.00 Generators	43.00	S0	43.00	38.26			2051	200-SC	42.54	35.71	-23.3	-23.3
345.00 Accessory Electric Equipment	43.00	S6	43.00	31.86			2051	200-SC	42.54	35.71	-23.3	-23.3
346.00 Miscellaneous Power Plant Equipment	38.00	R1	38.00	34.33			2051	200-SC	42.54	35.71	-23.3	-23.3
Total Enviromental			45.08	36.46					42.54	35.71	-23.3	-23.3

UNS ELECTRIC, INC.
Current and Proposed Parameters
Vintage Group Procedure

Statement G

Account Description	Current Parameters						Proposed Parameters					
	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Non-Enviromental												
341.00 Structures and Improvements	49.00	S6	49.00	40.31			2051	200-SC	44.19	35.70	-7.8	-8.8
342.00 Fuel Holders, Producers and Accessories	40.00	S4	40.00	31.64			2051	200-SC	47.11	35.69	-8.8	-8.8
343.00 Prime Movers	40.00	R3	40.00	28.50			2051	200-SC	48.18	35.67	-7.2	-8.8
344.00 Generators	43.00	S0	43.00	38.26			2051	200-SC	44.50	35.70	-8.7	-8.8
345.00 Accessory Electric Equipment	43.00	S6	43.00	31.86			2051	200-SC	46.76	35.68	-8.0	-8.8
346.00 Miscellaneous Power Plant Equipment	38.00	R1	38.00	34.33			2051	200-SC	42.53	35.71	-8.6	-8.8
Total Non-Enviromental			41.37	32.32					46.37	35.68	-7.8	-8.8
La Senita												
341.00 Structures and Improvements	49.00	S6					2036	200-SC	24.23	21.86	-14.1	-14.1
342.00 Fuel Holders, Producers and Accessories												
343.00 Prime Movers												
344.00 Generators	20.00	SQ	20.00				2036	200-SC	24.23	21.86	-14.1	-14.1
345.00 Accessory Electric Equipment												
346.00 Miscellaneous Power Plant Equipment												
Total La Senita			20.12						24.23	21.86	-14.1	-14.1
Rio Rico												
341.00 Structures and Improvements												
342.00 Fuel Holders, Producers and Accessories												
343.00 Prime Movers												
344.00 Generators	20.00	SQ	20.00				2039	200-SC	25.16	24.69	-16.2	-16.2
345.00 Accessory Electric Equipment												
346.00 Miscellaneous Power Plant Equipment												
Total Rio Rico			20.00						25.16	24.69	-16.2	-16.2

Statements A through G

UNS ELECTRIC, INC. (Gila River)
Component Accrual Rates
Current: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement A

Account Description	Current (at 12/31/2014) Investment	Net Salvage	Total	Proposed (at 12/31/2014) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
INTANGIBLE PLANT						
303.AP APS Contract	2.22%		2.22%	← 45 Year Amortization →		2.22%
303.S2 Control Software	20.00%		20.00%	← 5 Year Amortization →		20.00%
Total Intangible Plant	2.37%		2.37%	2.37%		2.37%
OTHER PRODUCTION						
341.00 Structures and Improvements	2.26%		2.26%	2.40%	0.20%	2.60%
342.00 Fuel Holders, Producers and Accessories	2.26%		2.26%	2.38%	0.20%	2.58%
343.00 Prime Movers	2.26%		2.26%	2.44%	0.20%	2.64%
344.00 Generators	2.26%		2.26%	2.38%	0.19%	2.57%
345.00 Accessory Electric Equipment	2.26%		2.26%	2.39%	0.20%	2.59%
346.00 Miscellaneous Power Plant Equipment	2.26%		2.26%	2.39%	0.20%	2.59%
Total Other Production Plant	2.26%		2.26%	2.42%	0.20%	2.62%
TRANSMISSION PLANT						
352.00 Structures and Improvements	2.93%		2.93%	1.68%	0.17%	1.85%
353.00 Station Equipment	3.02%		3.02%	1.71%	-0.17%	1.54%
Total Transmission Plant	3.02%		3.02%	1.71%	-0.17%	1.54%
GENERAL PLANT						
Depreciable						
390.00 Structures and Improvements	2.60%		2.60%	2.55%	0.12%	2.67%
392.C0 Transportation Equipment - Class 0	12.35%	-0.46%	11.89%	10.18%		10.18%
Total Depreciable	2.76%	-0.01%	2.75%	2.68%	0.12%	2.80%
Amortizable						
393.00 Stores Equipment	← 33 Year Amortization →		3.03%	← 15 Year Amortization →		6.67%
Total Amortizable	3.03%		3.03%	6.67%		6.67%
Total General Plant	2.77%	-0.01%	2.76%	2.72%	0.12%	2.84%
TOTAL UTILITY	2.29%		2.29%	2.40%	0.18%	2.58%
OTHER PRODUCTION						
Gila River						
341.00 Structures and Improvements	2.26%		2.26%	2.40%	0.20%	2.60%
342.00 Fuel Holders, Producers and Accessories	2.26%		2.26%	2.38%	0.20%	2.58%
343.00 Prime Movers	2.26%		2.26%	2.44%	0.20%	2.64%
344.00 Generators	2.26%		2.26%	2.38%	0.19%	2.57%
345.00 Accessory Electric Equipment	2.26%		2.26%	2.39%	0.20%	2.59%
346.00 Miscellaneous Power Plant Equipment	2.26%		2.26%	2.39%	0.20%	2.59%
Total Gila River	2.26%		2.26%	2.42%	0.20%	2.62%
Unit 3						
341.00 Structures and Improvements	2.26%		2.26%	2.39%	0.20%	2.59%
342.00 Fuel Holders, Producers and Accessories	2.26%		2.26%	2.45%	0.20%	2.65%
343.00 Prime Movers	2.26%		2.26%	2.43%	0.20%	2.63%
344.00 Generators	2.26%		2.26%	2.38%	0.19%	2.57%
345.00 Accessory Electric Equipment	2.26%		2.26%	2.39%	0.20%	2.59%
346.00 Miscellaneous Power Plant Equipment	2.26%		2.26%	2.41%	0.21%	2.62%
Total Unit 3	2.26%		2.26%	2.42%	0.20%	2.62%
Common						
341.00 Structures and Improvements	2.26%		2.26%	2.40%	0.20%	2.60%
342.00 Fuel Holders, Producers and Accessories	2.26%		2.26%	2.38%	0.20%	2.58%
343.00 Prime Movers	2.26%		2.26%	2.58%	0.22%	2.80%
344.00 Generators						
345.00 Accessory Electric Equipment	2.26%		2.26%	2.39%	0.20%	2.59%
346.00 Miscellaneous Power Plant Equipment	2.26%		2.26%	2.39%	0.20%	2.59%
Total Common	2.26%		2.26%	2.44%	0.20%	2.64%

UNS ELECTRIC, INC. (Gila River)
Component Accruals
Current: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/14	Current 2015 Annualized Accrual			Proposed 2015 Annualized Accrual			
	Investment	Investment	Net Salvage	Total	Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
INTANGIBLE PLANT								
303.AP APS Contract	$ 2,750,000	$ 61,111	$ -	$ 61,111	$ 61,111	$ -	$ 61,111	$ -
303.S2 Control Software	23,015	4,603		4,603	4,603		4,603	
Total Intangible Plant	$ 2,773,015	$ 65,714	$ -	$ 65,714	$ 65,714	$ -	$ 65,714	$ -
OTHER PRODUCTION								
341.00 Structures and Improvements	$ 2,836,317	$ 64,101	$ -	$ 64,101	$ 68,039	$ 5,672	$ 73,711	$ 9,610
342.00 Fuel Holders, Producers and Accessories	2,261,015	51,099		51,099	53,854	4,522	58,376	7,277
343.00 Prime Movers	62,914,910	1,421,877		1,421,877	1,532,419	126,308	1,658,727	236,850
344.00 Generators	10,927,811	246,969		246,969	260,082	20,763	280,845	33,876
345.00 Accessory Electric Equipment	3,010,232	68,031		68,031	71,945	6,021	77,966	9,935
346.00 Miscellaneous Power Plant Equipment	2,266,653	51,226		51,226	54,182	4,538	58,720	7,494
Total Other Production Plant	$ 84,216,938	$ 1,903,303	$ -	$ 1,903,303	$ 2,040,521	$ 167,824	$ 2,208,345	$ 305,042
TRANSMISSION PLANT								
352.00 Structures and Improvements	$ 45,401	$ 1,330	$ -	$ 1,330	$ 763	$ 77	$ 840	$ (490)
353.00 Station Equipment	3,209,876	96,938		96,938	54,889	(5,457)	49,432	(47,506)
Total Transmission Plant	$ 3,255,277	$ 98,268	$ -	$ 98,268	$ 55,652	$ (5,380)	$ 50,272	$ (47,996)
GENERAL PLANT								
Depreciable								
390.00 Structures and Improvements	$ 644,404	$ 16,755	$ -	$ 16,755	$ 16,432	$ 773	$ 17,205	$ 450
392.C0 Transportation Equipment - Class 0	11,039	1,363	(51)	1,312	1,124		1,124	(188)
Total Depreciable	$ 655,443	$ 18,118	$ (51)	$ 18,067	$ 17,556	$ 773	$ 18,329	$ 262
Amortizable								
393.00 Stores Equipment	$ 7,434	$ 225	$ -	$ 225	$ 496	$ -	$ 496	$ 271
Total Amortizable	$ 7,434	$ 225	$ -	$ 225	$ 496	$ -	$ 496	$ 271
Total General Plant	$ 662,877	$ 18,343	$ (51)	$ 18,292	$ 18,052	$ 773	$ 18,825	$ 533
TOTAL UTILITY	$ 90,908,107	$ 2,085,628	$ (51)	$ 2,085,577	$ 2,179,939	$ 163,217	$ 2,343,156	$ 257,579

UNS ELECTRIC, INC. (Gila River)
Component Accruals
Current: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/14	Current 2015 Annualized Accrual			Proposed 2015 Annualized Accrual			
	Investment	Investment	Net Salvage	Total	Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
OTHER PRODUCTION								
Gila River								
341.00 Structures and Improvements	$ 2,836,317	$ 64,101	$ -	$ 64,101	$ 68,039	$ 5,672	$ 73,711	$ 9,610
342.00 Fuel Holders, Producers and Accessories	2,261,015	51,099		51,099	53,854	4,522	58,376	7,277
343.00 Prime Movers	62,914,910	1,421,877		1,421,877	1,532,419	126,308	1,658,727	236,850
344.00 Generators	10,927,811	246,969		246,969	260,082	20,763	280,845	33,876
345.00 Accessory Electric Equipment	3,010,232	68,031		68,031	71,945	6,021	77,966	9,935
346.00 Miscellaneous Power Plant Equipment	2,266,653	51,226		51,226	54,182	4,538	58,720	7,494
Total Gila River	$ 84,216,938	$ 1,903,303	$ -	$ 1,903,303	$ 2,040,521	$ 167,824	$ 2,208,345	$ 305,042
Unit 3								
341.00 Structures and Improvements	$ 319,139	$ 7,213	$ -	$ 7,213	$ 7,627	$ 638	$ 8,265	$ 1,052
342.00 Fuel Holders, Producers and Accessories	59,475	1,344		1,344	1,457	119	1,576	232
343.00 Prime Movers	60,523,904	1,367,840		1,367,840	1,470,731	121,048	1,591,779	223,939
344.00 Generators	10,927,811	246,969		246,969	260,082	20,763	280,845	33,876
345.00 Accessory Electric Equipment	2,286,851	51,683		51,683	54,656	4,574	59,230	7,547
346.00 Miscellaneous Power Plant Equipment	45,186	1,021		1,021	1,089	95	1,184	163
Total Unit 3	$ 74,162,366	$ 1,676,070	$ -	$ 1,676,070	$ 1,795,642	$ 147,237	$ 1,942,879	$ 266,809
Common								
341.00 Structures and Improvements	$ 2,517,178	$ 56,888	$ -	$ 56,888	$ 60,412	$ 5,034	$ 65,446	$ 8,558
342.00 Fuel Holders, Producers and Accessories	2,201,540	49,755		49,755	52,397	4,403	56,800	7,045
343.00 Prime Movers	2,391,006	54,037		54,037	61,688	5,260	66,948	12,911
344.00 Generators								
345.00 Accessory Electric Equipment	723,381	16,348		16,348	17,289	1,447	18,736	2,388
346.00 Miscellaneous Power Plant Equipment	2,221,467	50,205		50,205	53,093	4,443	57,536	7,331
Total Common	$ 10,054,572	$ 227,233	$ -	$ 227,233	$ 244,879	$ 20,587	$ 265,466	$ 38,233

UNS ELECTRIC, INC. (Gila River)
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2014

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
INTANGIBLE PLANT							
303.AP APS Contract	$ 2,750,000	$ 700,666	25.48%	$ 702,778	25.56%	$ 702,778	25.56%
303.S2 Control Software	23,015	6,713	29.17%	6,905	30.00%	6,905	30.00%
Total Intangible Plant	$ 2,773,015	$ 707,378	25.51%	$ 709,682	25.59%	$ 709,682	25.59%
OTHER PRODUCTION							
341.00 Structures and Improvements	$ 2,836,317	$ 706,271	24.90%	$ 737,350	26.00%	$ 709,404	25.01%
342.00 Fuel Holders, Producers and Accessories	2,261,015	562,952	24.90%	601,414	26.60%	578,620	25.59%
343.00 Prime Movers	62,914,910	14,995,379	23.83%	15,458,606	24.57%	14,872,711	23.64%
344.00 Generators	10,927,811	2,754,719	25.21%	2,934,413	26.85%	2,823,196	25.83%
345.00 Accessory Electric Equipment	3,010,232	744,729	24.74%	794,182	26.38%	764,082	25.38%
346.00 Miscellaneous Power Plant Equipment	2,266,653	557,752	24.61%	593,999	26.21%	571,485	25.21%
Total Other Production Plant	$ 84,216,938	$ 20,321,802	24.13%	$ 21,119,964	25.08%	$ 20,319,498	24.13%
TRANSMISSION PLANT							
352.00 Structures and Improvements	$ 45,401	$ 5,722	12.60%	$ 10,442	23.00%	$ 13,463	29.65%
353.00 Station Equipment	3,209,876	586,537	18.27%	448,942	13.99%	578,797	18.03%
Total Transmission Plant	$ 3,255,277	$ 592,260	18.19%	$ 459,384	14.11%	$ 592,260	18.19%
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	$ 644,404	$ 163,696	25.40%	$ 171,650	26.64%	$ 161,961	25.13%
392.C0 Transportation Equipment - Class 0	11,039	2,979	26.99%	4,993	45.23%	4,711	42.68%
Total Depreciable	$ 655,443	$ 166,675	25.43%	$ 176,644	26.95%	$ 166,673	25.43%
Amortizable							
393.00 Stores Equipment	$ 7,434	$ 3,715	49.97%	$ 3,717	50.00%	$ 3,717	50.00%
Total Amortizable	$ 7,434	$ 3,715	49.97%	$ 3,717	50.00%	$ 3,717	50.00%
Total General Plant	$ 662,877	$ 170,390	25.70%	$ 180,361	27.21%	$ 170,390	25.70%
TOTAL UTILITY	$ 90,908,107	$ 21,791,830	23.97%	$ 22,469,391	24.72%	$ 21,791,830	23.97%

UNS ELECTRIC, INC. (Gila River)
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2014

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
OTHER PRODUCTION							
Gila River							
341.00 Structures and Improvements	$ 2,836,317	$ 706,271	24.90%	$ 737,350	26.00%	$ 709,404	25.01%
342.00 Fuel Holders, Producers and Accessories	2,261,015	562,952	24.90%	601,414	26.60%	578,620	25.59%
343.00 Prime Movers	62,914,910	14,995,379	23.83%	15,458,606	24.57%	14,872,711	23.64%
344.00 Generators	10,927,811	2,754,719	25.21%	2,934,413	26.85%	2,823,196	25.83%
345.00 Accessory Electric Equipment	3,010,232	744,729	24.74%	794,182	26.38%	764,082	25.38%
346.00 Miscellaneous Power Plant Equipment	2,266,653	557,752	24.61%	593,999	26.21%	571,485	25.21%
Total Gila River	$ 84,216,938	$ 20,321,802	24.13%	$ 21,119,964	25.08%	$ 20,319,498	24.13%
Unit 3							
341.00 Structures and Improvements	$ 319,139	$ 86,050	26.96%	$ 84,164	26.37%	$ 80,974	25.37%
342.00 Fuel Holders, Producers and Accessories	59,475	13,472	22.65%	14,338	24.11%	13,795	23.19%
343.00 Prime Movers	60,523,904	14,573,887	24.08%	14,995,325	24.78%	14,426,989	23.84%
344.00 Generators	10,927,811	2,754,719	25.21%	2,934,413	26.85%	2,823,196	25.83%
345.00 Accessory Electric Equipment	2,286,851	565,641	24.73%	603,094	26.37%	580,236	25.37%
346.00 Miscellaneous Power Plant Equipment	45,186	10,953	24.24%	11,484	25.41%	11,048	24.45%
Total Unit 3	$ 74,162,366	$ 18,004,722	24.28%	$ 18,642,818	25.14%	$ 17,936,239	24.19%
Common							
341.00 Structures and Improvements	$ 2,517,178	$ 620,220	24.64%	$ 653,186	25.95%	$ 628,430	24.97%
342.00 Fuel Holders, Producers and Accessories	2,201,540	549,480	24.96%	587,076	26.67%	564,825	25.66%
343.00 Prime Movers	2,391,006	421,492	17.63%	463,281	19.38%	445,722	18.64%
344.00 Generators					#DIV/0!		
345.00 Accessory Electric Equipment	723,381	179,088	24.76%	191,088	26.42%	183,846	25.41%
346.00 Miscellaneous Power Plant Equipment	2,221,467	546,799	24.61%	582,515	26.22%	560,437	25.23%
Total Common	$ 10,054,572	$ 2,317,080	23.05%	$ 2,477,146	24.64%	$ 2,383,260	23.70%

UNS ELECTRIC, INC. (Gila River)
Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	I=C+E+G	J=I/B
INTANGIBLE PLANT							
303.AP APS Contract	$ 2,750,000	$ 702,778	25.56%	$ -		$ 702,778	25.56%
303.S2 Control Software	23,015	6,905	30.00%			6,905	30.00%
Total Intangible Plant	$ 2,773,015	$ 709,682	25.59%	$ -		$ 709,682	25.59%
OTHER PRODUCTION							
341.00 Structures and Improvements	$ 2,836,317	$ 654,501	23.08%	$ 54,903	1.94%	$ 709,404	25.01%
342.00 Fuel Holders, Producers and Accessories	2,261,015	533,794	23.61%	44,826	1.98%	578,620	25.59%
343.00 Prime Movers	62,914,910	13,732,502	21.83%	1,140,209	1.81%	14,872,711	23.64%
344.00 Generators	10,927,811	2,606,830	23.86%	216,367	1.98%	2,823,196	25.83%
345.00 Accessory Electric Equipment	3,010,232	705,367	23.43%	58,715	1.95%	764,082	25.38%
346.00 Miscellaneous Power Plant Equipment	2,266,653	527,210	23.26%	44,275	1.95%	571,485	25.21%
Total Other Production Plant	$ 84,216,938	$ 18,760,203	22.28%	$ 1,559,295	1.85%	$ 20,319,498	24.13%
TRANSMISSION PLANT							
352.00 Structures and Improvements	$ 45,401	$ 12,239	26.96%	$ 1,224	2.70%	$ 13,463	29.65%
353.00 Station Equipment	3,209,876	643,108	20.04%	(64,311)	-2.00%	578,797	18.03%
Total Transmission Plant	$ 3,255,277	$ 655,347	20.13%	$ (63,087)	-1.94%	$ 592,260	18.19%
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	$ 644,404	$ 154,249	23.94%	$ 7,712	1.20%	$ 161,961	25.13%
392.C0 Transportation Equipment - Class 0	11,039	4,711	42.68%			4,711	42.68%
Total Depreciable	$ 655,443	$ 158,960	24.25%	$ 7,712	1.18%	$ 166,673	25.43%
Amortizable							
393.00 Stores Equipment	$ 7,434	$ 3,717	50.00%	$ -		$ 3,717	50.00%
Total Amortizable	$ 7,434	$ 3,717	50.00%	$ -		$ 3,717	50.00%
Total General Plant	$ 662,877	$ 162,677	24.54%	$ 7,712	1.16%	$ 170,390	25.70%
TOTAL UTILITY	$ 90,908,107	$ 20,287,909	22.32%	$ 1,503,921	1.65%	$ 21,791,830	23.97%

UNS ELECTRIC, INC. (Gila River)
Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	I=C+E+G	J=I/B
OTHER PRODUCTION							
Gila River							
341.00 Structures and Improvements	$ 2,836,317	$ 654,501	23.08%	$ 54,903	1.94%	$ 709,404	25.01%
342.00 Fuel Holders, Producers and Accessories	2,261,015	533,794	23.61%	44,826	1.98%	578,620	25.59%
343.00 Prime Movers	62,914,910	13,732,502	21.83%	1,140,209	1.81%	14,872,711	23.64%
344.00 Generators	10,927,811	2,606,830	23.86%	216,367	1.98%	2,823,196	25.83%
345.00 Accessory Electric Equipment	3,010,232	705,367	23.43%	58,715	1.95%	764,082	25.38%
346.00 Miscellaneous Power Plant Equipment	2,266,653	527,210	23.26%	44,275	1.95%	571,485	25.21%
Total Gila River	$ 84,216,938	$ 18,760,203	22.28%	$ 1,559,295	1.85%	$ 20,319,498	24.13%
Unit 3							
341.00 Structures and Improvements	$ 319,139	$ 74,768	23.43%	$ 6,206	1.94%	$ 80,974	25.37%
342.00 Fuel Holders, Producers and Accessories	59,475	12,737	21.42%	1,057	1.78%	13,795	23.19%
343.00 Prime Movers	60,523,904	13,321,319	22.01%	1,105,669	1.83%	14,426,989	23.84%
344.00 Generators	10,927,811	2,606,830	23.86%	216,367	1.98%	2,823,196	25.83%
345.00 Accessory Electric Equipment	2,286,851	535,768	23.43%	44,469	1.94%	580,236	25.37%
346.00 Miscellaneous Power Plant Equipment	45,186	10,202	22.58%	847	1.87%	11,048	24.45%
Total Unit 3	$ 74,162,366	$ 16,561,624	22.33%	$ 1,374,615	1.85%	$ 17,936,239	24.19%
Common							
341.00 Structures and Improvements	$ 2,517,178	$ 579,732	23.03%	$ 48,697	1.93%	$ 628,430	24.97%
342.00 Fuel Holders, Producers and Accessories	2,201,540	521,057	23.67%	43,769	1.99%	564,825	25.66%
343.00 Prime Movers	2,391,006	411,183	17.20%	34,539	1.44%	445,722	18.64%
344.00 Generators							
345.00 Accessory Electric Equipment	723,381	169,599	23.45%	14,246	1.97%	183,846	25.41%
346.00 Miscellaneous Power Plant Equipment	2,221,467	517,008	23.27%	43,429	1.95%	560,437	25.23%
Total Common	$ 10,054,572	$ 2,198,579	21.87%	$ 184,681	1.84%	$ 2,383,260	23.70%

UNS ELECTRIC, INC. (Gila River)
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
INTANGIBLE PLANT									
303.AP APS Contract	$ 2,750,000	$ -	$ 2,750,000			$ -	$ -	$ -	
303.S2 Control Software	23,015		23,015						
Total Intangible Plant	$ 2,773,015	$ -	$ 2,773,015			$ -	$ -	$ -	
OTHER PRODUCTION									
341.00 Structures and Improvements	$ 2,836,317	$ -	$ 2,836,317		-8.4%	$ -	$ (237,931)	$ (237,931)	-8.4%
342.00 Fuel Holders, Producers and Accessories	2,261,015		2,261,015		-8.4%		(189,866)	(189,866)	-8.4%
343.00 Prime Movers	62,914,910		62,914,910		-8.3%		(5,224,329)	(5,224,329)	-8.3%
344.00 Generators	10,927,811		10,927,811		-8.3%		(907,008)	(907,008)	-8.3%
345.00 Accessory Electric Equipment	3,010,232		3,010,232		-8.3%		(250,573)	(250,573)	-8.3%
346.00 Miscellaneous Power Plant Equipment	2,266,653		2,266,653		-8.4%		(190,354)	(190,354)	-8.4%
Total Other Production Plant	$ 84,216,938	$ -	$ 84,216,938		-8.3%	$ -	$ (7,000,060)	$ (7,000,060)	-8.3%
TRANSMISSION PLANT									
352.00 Structures and Improvements	$ 45,401	$ -	$ 45,401		-10.0%	$ -	$ (4,540)	$ (4,540)	-10.0%
353.00 Station Equipment	3,209,876		3,209,876		10.0%		320,988	320,988	10.0%
Total Transmission Plant	$ 3,255,277	$ -	$ 3,255,277		9.7%	$ -	$ 316,448	$ 316,448	9.7%
GENERAL PLANT									
Depreciable									
390.00 Structures and Improvements	$ 644,404	$ -	$ 644,404		-5.0%	$ -	$ (32,220)	$ (32,220)	-5.0%
392.C0 Transportation Equipment - Class 0	11,039		11,039						
Total Depreciable	$ 655,443	$ -	$ 655,443		-4.9%	$ -	$ (32,220)	$ (32,220)	-4.9%
Amortizable									
393.00 Stores Equipment	$ 7,434	$ -	$ 7,434			$ -	$ -	$ -	
Total Amortizable	$ 7,434	$ -	$ 7,434			$ -	$ -	$ -	
Total General Plant	$ 662,877	$ -	$ 662,877		-4.9%	$ -	$ (32,220)	$ (32,220)	-4.9%
TOTAL UTILITY	$ 90,908,107	$ -	$ 90,908,107		-7.4%	$ -	$ (6,715,833)	$ (6,715,833)	-7.4%

UNS ELECTRIC, INC. (Gila River)
Average Net Salvage

Statement E

Account Description	Plant Investment: Additions	Plant Investment: Retirements	Plant Investment: Survivors	Salvage Rate: Realized	Salvage Rate: Future	Net Salvage: Realized	Net Salvage: Future	Net Salvage: Total	Average Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
OTHER PRODUCTION									
Gila River									
341.00 Structures and Improvements	$ 2,836,317	$ -	$ 2,836,317		-8.4%	$ -	$ (237,931)	$ (237,931)	-8.4%
342.00 Fuel Holders, Producers and Accessories	2,261,015		2,261,015		-8.4%		(189,866)	(189,866)	-8.4%
343.00 Prime Movers	62,914,910		62,914,910		-8.3%		(5,224,329)	(5,224,329)	-8.3%
344.00 Generators	10,927,811		10,927,811		-8.3%		(907,008)	(907,008)	-8.3%
345.00 Accessory Electric Equipment	3,010,232		3,010,232		-8.3%		(250,573)	(250,573)	-8.3%
346.00 Miscellaneous Power Plant Equipment	2,266,653		2,266,653		-8.4%		(190,354)	(190,354)	-8.4%
Total Gila River	$ 84,216,938	$ -	$ 84,216,938		-8.3%	$ -	$ (7,000,060)	$ (7,000,060)	-8.3%
Unit 3									
341.00 Structures and Improvements	$ 319,139	$ -	$ 319,139		-8.3%	$ -	$ (26,489)	$ (26,489)	-8.3%
342.00 Fuel Holders, Producers and Accessories	59,475		59,475		-8.3%		(4,936)	(4,936)	-8.3%
343.00 Prime Movers	60,523,904		60,523,904		-8.3%		(5,023,484)	(5,023,484)	-8.3%
344.00 Generators	10,927,811		10,927,811		-8.3%		(907,008)	(907,008)	-8.3%
345.00 Accessory Electric Equipment	2,286,851		2,286,851		-8.3%		(189,809)	(189,809)	-8.3%
346.00 Miscellaneous Power Plant Equipment	45,186		45,186		-8.3%		(3,750)	(3,750)	-8.3%
Total Unit 3	$ 74,162,366	$ -	$ 74,162,366		-8.3%	$ -	$ (6,155,476)	$ (6,155,476)	-8.3%
Common									
341.00 Structures and Improvements	$ 2,517,178	$ -	$ 2,517,178		-8.4%	$ -	$ (211,443)	$ (211,443)	-8.4%
342.00 Fuel Holders, Producers and Accessories	2,201,540		2,201,540		-8.4%		(184,929)	(184,929)	-8.4%
343.00 Prime Movers	2,391,006		2,391,006		-8.4%		(200,845)	(200,845)	-8.4%
344.00 Generators									
345.00 Accessory Electric Equipment	723,381		723,381		-8.4%		(60,764)	(60,764)	-8.4%
346.00 Miscellaneous Power Plant Equipment	2,221,467		2,221,467		-8.4%		(186,603)	(186,603)	-8.4%
Total Common	$ 10,054,572	$ -	$ 10,054,572		-8.4%	$ -	$ (844,584)	$ (844,584)	-8.4%

UNS ELECTRIC, INC. (Gila River)
Future Net Salvage
Other Production

Statement F

Account Description	12/31/14 Plant Investment	Future Retirements		Net Salvage Rate		Future Net Salvage			Future Rate
		Interim	Final	Interim	Final	Interim	Final	Total	
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
OTHER PRODUCTION									
Gila River									
Unit 3									
341.00 Structures and Improvements	$ 319,139	$ 27,093	$ 292,046		-9.1%	$ -	$ (26,499)	$ (26,499)	-8.3%
342.00 Fuel Holders, Producers and Accessori	59,475	5,037	54,438		-9.1%		(4,939)	(4,939)	-8.3%
343.00 Prime Movers	60,523,904	5,128,667	55,395,237		-9.1%		(5,026,270)	(5,026,270)	-8.3%
344.00 Generators	10,927,811	928,233	9,999,578		-9.1%		(907,309)	(907,309)	-8.3%
345.00 Accessory Electric Equipment	2,286,851	194,145	2,092,706		-9.1%		(189,881)	(189,881)	-8.3%
346.00 Miscellaneous Power Plant Equipment	45,186	3,831	41,355		-9.1%		(3,752)	(3,752)	-8.3%
Total Unit 3	$ 74,162,366	$ 6,287,006	$ 67,875,360		-9.1%	$ -	$ (6,158,650)	$ (6,158,650)	-8.3%
Common									
341.00 Structures and Improvements	$ 2,517,178	$ 213,575	$ 2,303,603		-9.1%	$ -	$ (210,220)	$ (210,220)	-8.4%
342.00 Fuel Holders, Producers and Accessori	2,201,540	186,950	2,014,590		-9.1%		(183,846)	(183,846)	-8.4%
343.00 Prime Movers	2,391,006	201,337	2,189,669		-9.1%		(199,823)	(199,823)	-8.4%
344.00 Generators									
345.00 Accessory Electric Equipment	723,381	61,414	661,967		-9.1%		(60,409)	(60,409)	-8.4%
346.00 Miscellaneous Power Plant Equipment	2,221,467	188,552	2,032,915		-9.1%		(185,518)	(185,518)	-8.4%
Total Common	$ 10,054,572	$ 851,828	$ 9,202,744		-9.1%	$ -	$ (839,816)	$ (839,816)	-8.4%

UNS ELECTRIC, INC. (Gila River)
Current and Proposed Parameters
Vintage Group Procedure

Statement G

Account Description	Current Parameters: P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters: P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
INTANGIBLE PLANT												
303.AP APS Contract	45.00	SQ	45.00				45.00	SQ	45.00	33.50		
303.S2 Control Software	5.00	SQ	5.00				5.00	SQ	5.00	3.50		
Total Intangible Plant			42.20						42.20	31.40		9.7
OTHER PRODUCTION												
341.00 Structures and Improvements	45.00	SQ	45.00				2048	200-SC	42.18	32.06	-8.4	-8.4
342.00 Fuel Holders, Producers and Accessories	45.00	SQ	45.00				2048	200-SC	42.49	32.06	-8.4	-8.4
343.00 Prime Movers	45.00	SQ	45.00				2048	200-SC	41.47	32.06	-8.3	-8.3
344.00 Generators	45.00	SQ	45.00				2048	200-SC	42.63	32.06	-8.3	-8.3
345.00 Accessory Electric Equipment	45.00	SQ	45.00				2048	200-SC	42.38	32.06	-8.3	-8.3
346.00 Miscellaneous Power Plant Equipment	45.00	SQ	45.00				2048	200-SC	42.28	32.06	-8.4	-8.4
Total Other Production Plant			45.00						41.72	32.06	-8.3	-8.3
TRANSMISSION PLANT												
352.00 Structures and Improvements	33.00	R3	33.00				55.00	R5	55.00	43.50	-10.0	-10.0
353.00 Station Equipment	32.00	R1	32.00				55.00	R1	55.34	46.74	10.0	10.0
Total Transmission Plant			32.01						55.34	46.69	9.7	9.7
GENERAL PLANT												
Depreciable												
390.00 Structures and Improvements	38.00	R2	38.00				40.00	R4	40.01	29.86	-5.0	-5.0
392.C0 Transportation Equipment - Class 0	8.00	L1.5	8.00			10.0	10.00	L2	10.28	5.63		
Total Depreciable			35.74						38.15	28.35	-4.9	-4.9
Amortizable												
393.00 Stores Equipment	33.00	SQ	33.00				15.00	SQ	15.00	7.50		
Total Amortizable			33.00						15.00	7.50		
Total General Plant									37.50	27.76	-4.9	-4.9
TOTAL UTILITY									42.07	32.40	-7.4	-7.4

UNS ELECTRIC, INC. (Gila River)
Current and Proposed Parameters
Vintage Group Procedure

Statement G

Account Description	Current Parameters						Proposed Parameters					
	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
OTHER PRODUCTION												
Gila River												
341.00 Structures and Improvements	45.00	SQ	45.00				2048	200-SC	42.18	32.06	-8.4	-8.4
342.00 Fuel Holders, Producers and Accessories	45.00	SQ	45.00				2048	200-SC	42.49	32.06	-8.4	-8.4
343.00 Prime Movers	45.00	SQ	45.00				2048	200-SC	41.47	32.06	-8.3	-8.3
344.00 Generators	45.00	SQ	45.00				2048	200-SC	42.63	32.06	-8.3	-8.3
345.00 Accessory Electric Equipment	45.00	SQ	45.00				2048	200-SC	42.38	32.06	-8.3	-8.3
346.00 Miscellaneous Power Plant Equipment	45.00	SQ	45.00				2048	200-SC	42.28	32.06	-8.4	-8.4
Total Gila River			45.00						41.72	32.06	-8.3	-8.3
Unit 3												
341.00 Structures and Improvements	45.00	SQ	45.00				2048	200-SC	42.38	32.06	-8.3	-8.3
342.00 Fuel Holders, Producers and Accessories	45.00	SQ	45.00				2048	200-SC	41.24	32.06	-8.3	-8.3
343.00 Prime Movers	45.00	SQ	45.00				2048	200-SC	41.57	32.06	-8.3	-8.3
344.00 Generators	45.00	SQ	45.00				2048	200-SC	42.63	32.06	-8.3	-8.3
345.00 Accessory Electric Equipment	45.00	SQ	45.00				2048	200-SC	42.38	32.06	-8.3	-8.3
346.00 Miscellaneous Power Plant Equipment	45.00	SQ	45.00				2048	200-SC	41.89	32.06	-8.3	-8.3
Total Unit 3			45.00						41.75	32.06	-8.3	-8.3
Common												
341.00 Structures and Improvements	45.00	SQ	45.00				2048	200-SC	42.15	32.06	-8.4	-8.4
342.00 Fuel Holders, Producers and Accessories	45.00	SQ	45.00				2048	200-SC	42.52	32.06	-8.4	-8.4
343.00 Prime Movers	45.00	SQ	45.00				2048	200-SC	39.05	32.07	-8.4	-8.4
344.00 Generators												
345.00 Accessory Electric Equipment	45.00	SQ	45.00				2048	200-SC	42.39	32.06	-8.4	-8.4
346.00 Miscellaneous Power Plant Equipment	45.00	SQ	45.00				2048	200-SC	42.29	32.06	-8.4	-8.4
Total Common			45.00						41.49	32.06	-8.4	-8.4

ANALYSIS

INTRODUCTION

This section provides an explanation of the supporting schedules developed in the UNS Electric depreciation study to estimate appropriate projection curves, projection lives and statistics for each rate category. The form and content of the schedules developed for an account depend upon the method of analysis adopted for the category.

This section also includes an example of the supporting schedules developed for Account 362.00 – Station Equipment. Documentation for all other plant accounts is contained in the review work papers. The supporting schedules developed in the UNS Electric review include:

Schedule A – Generation Arrangement;

Schedule B – Age Distribution;

Schedule C – Plant History;

Schedule D – Actuarial Life Analysis;

Schedule E – Graphics Analysis; and

Schedule F – Historical Net Salvage Analysis.

The format and content of these schedules are briefly described below.

SCHEDULE A – GENERATION ARRANGEMENT

The purpose of this schedule is to obtain appropriate weighted–average life statistics for a rate category. The weighted–average remaining–life is the sum of Column H divided by the sum of Column I. The weighted average life is the sum of Column C divided by the sum of Column I.

It should be noted that the generation arrangement does not include parameters for net salvage. Computed Net Plant (Column H) and Accruals (Column I) must be adjusted for net salvage to obtain a correct measurement of theoretical reserves and annualized depreciation accruals.

The following table provides a description of each column in the generation arrangement.

Column	Title	Description
A	Vintage	Vintage or placement year of surviving plant.
B	Age	Age of surviving plant at beginning of study year.
C	Surviving Plant	Actual dollar amount of surviving plant.
D	Average Life	Estimated average life of each vintage. This statistic is the sum of the realized life and the unrealized life, which is the product of the remaining life (Column E) and the theoretical proportion surviving.
E	Remaining Life	Estimated remaining life of each vintage.
F	Net Plant Ratio	Theoretical net plant ratio of each vintage.
G	Allocation Factor	A pivotal ratio which determines the amortization period of the difference between the recorded and computed
H	Computed Net Plant	Plant in service less theoretical reserve for each vintage.
I	Accrual	Ratio of computed net plant (Column H) and remaining life (Column E).

Table 5. Generation Arrangement

SCHEDULE B – AGE DISTRIBUTION

This schedule provides the age distribution and realized life of surviving plant shown in Column C of the Generation Arrangement (Schedule A). The format of the schedule depends upon the availability of either aged or unaged data. Derived additions for vintage years older than the earliest activity year in an account for unaged data are obtained from the age distribution of surviving plant at the beginning of the earliest activity year. The amount surviving from these vintages is shown in Column D. The realized life (Column G) is derived from the dollar years of service provided by a vintage over the period of years the vintage has been in service. Plant additions for vintages older than the earliest activity year in an account are represented by the opening balances shown in Column D.

The computed proportion surviving (Column D) for unaged is derived from a computed mortality analysis. The average service life displayed in the title block is the life statistic derived for the most recent activity year, given the derived age distribution at the start of the year and the specified retirement dispersion. The realized life (Column F) is obtained by finding the slope of an SC retirement dispersion, which connects the computed survivors of a vintage (Column E) to the recorded vintage addition (Column B). The realized life is the area bounded by the SC dispersion, the computed proportion surviving and the age of the vintage.

SCHEDULE C – PLANT HISTORY

An Unadjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Activity year totals for unaged data are obtained from a transaction file without vintage identification. Information displayed in the unadjusted plant history is consistent with regulated investments reported internally by the Company.

An Adjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company with sales, transfers, and adjustments appropriately aged for depreciation study purposes. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Ageing of adjusting transactions is achieved using transaction codes that identify an adjusting year associated with the dollar amount of a transaction. Adjusting transactions processed in the adjusted plant history are not aged in the Company's records or in the unadjusted plant history.

SCHEDULE D – ACTUARIAL LIFE ANALYSIS

These schedules provide a summary of the dispersion and life indications obtained from an actuarial life analysis for a specified placement band. The observation band (Column A) is specified to produce a rolling–band, shrinking–band, or progressive–band analysis depending upon the movement of the end points of the band. The degree of censoring (or point of truncation) of the observed life table is shown in Column B for each observation band. The estimated average service life, best fitting Iowa dispersion, and a statistical measure of the goodness of fit are shown for each degree polynomial (First, Second, and Third) fitted to the estimated hazard rates. Options available in the analysis include the width and location of both the placement and observation bands; the interval of years included in a selected rolling, shrinking, or progressive band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated.

Estimated projection lives (Columns C, F, and I) are flagged with an asterisk if negative hazard rates are indicated by the fitted polynomial. All negative hazard rates are set equal to zero in the calculation of the graduated survivor curve. The Conformance Index (Columns E, H, and K) is the square root of the mean sum–of–squared differences between the graduated survivor curve and the best fitting Iowa curve. A Conformance Index of zero would indicate a perfect fit.

SCHEDULE E – GRAPHICS ANALYSIS

This schedule provides a graphics plot of a) the observed proportion surviving for a selected placement and observation band; b) the statistically best fitting Iowa dispersion and derived projection life; and c) the projection curve and projection life selected to describe future forces of mortality.

The graphics analysis also provides a plot of the observed hazard rates and graduated hazard function for a selected placement and observation band. The estimator of the hazard rates and weighting used in fitting orthogonal polynomials to the observed data are displayed in the title block of the displayed graph.

SCHEDULE F – HISTORICAL NET SALVAGE ANALYSIS

This schedule provides a moving average analysis of the ratio of realized net salvage (Column I) to the associated retirements (Column B). The schedule also provides a moving average analysis of the components of net salvage related to retirements. The ratio of gross salvage to retirements is shown in Column D and the ratio of cost of removal to retirements is shown in Column G.

UNS Electric, Inc.

Distribution Plant
Account: 362.00 Station Equipment

Dispersion: 56 - L1.5
Procedure: Vintage Group

Generation Arrangement

Vintage	Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
	December 31, 2013							
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2013	0.5	6,542,156	56.00	55.51	0.9913	1.0000	6,485,423	116,824
2012	1.5	1,100,568	56.00	54.55	0.9741	1.0000	1,072,022	19,653
2011	2.5	8,630,453	56.00	53.59	0.9569	1.0000	8,258,663	154,110
2010	3.5	1,791,352	56.00	52.64	0.9399	1.0000	1,683,751	31,986
2009	4.5	7,332,343	56.01	51.70	0.9231	1.0000	6,768,467	130,919
2008	5.5	3,460,565	56.01	50.77	0.9065	1.0000	3,136,856	61,783
2007	6.5	5,198,366	56.02	49.86	0.8900	1.0000	4,626,668	92,799
2006	7.5	3,090,591	56.01	48.95	0.8741	1.0000	2,701,376	55,181
2005	8.5	178,505	55.79	48.07	0.8615	1.0000	153,788	3,199
2004	9.5	54,226	56.05	47.19	0.8420	1.0000	45,659	967
2003	10.5	1,534,488	56.06	46.34	0.8265	1.0000	1,268,264	27,371
2002	11.5	579,054	55.93	45.49	0.8134	1.0000	471,014	10,353
2001	12.5	863,848	56.07	44.67	0.7966	1.0000	688,178	15,406
2000	13.5	1,420,004	56.13	43.86	0.7814	1.0000	1,109,546	25,299
1999	14.5	2,111,358	55.96	43.06	0.7695	1.0000	1,624,770	37,730
1998	15.5	800,724	56.18	42.29	0.7526	1.0000	602,646	14,252
1997	16.5	2,831,339	56.06	41.52	0.7408	1.0000	2,097,346	50,509
1996	17.5	1,128,265	56.28	40.78	0.7245	1.0000	817,458	20,047
1995	18.5	675,452	55.53	40.05	0.7212	1.0000	487,103	12,163
1994	19.5	144,474	53.15	39.33	0.7401	1.0000	106,921	2,718
1993	20.5	1,221,432	57.01	38.63	0.6777	1.0000	827,819	21,427
1992	21.5	716,267	56.43	37.95	0.6726	1.0000	481,752	12,693
1991	22.5	819,767	56.61	37.29	0.6588	1.0000	540,034	14,481
1990	23.5	108,375	56.64	36.65	0.6471	1.0000	70,131	1,913
1989	24.5	1,251,979	55.69	36.03	0.6470	1.0000	809,982	22,479
1988	25.5	254,534	56.90	35.43	0.6227	1.0000	158,503	4,473
1987	26.5	733,676	57.02	34.85	0.6112	1.0000	448,437	12,866
1986	27.5	541,302	57.13	34.30	0.6004	1.0000	324,977	9,476
1985	28.5	97,734	57.01	33.76	0.5922	1.0000	57,875	1,714
1984	29.5	155,819	57.45	33.24	0.5786	1.0000	90,162	2,712
1983	30.5	62,672	53.71	32.75	0.6097	1.0000	38,209	1,167
1982	31.5	606,500	57.80	32.27	0.5583	1.0000	338,622	10,494
1981	32.5	1,582,968	57.95	31.81	0.5489	1.0000	868,858	27,316
1980	33.5	606,003	55.90	31.36	0.5610	1.0000	339,996	10,840
1979	34.5	395,973	58.35	30.93	0.5302	1.0000	209,938	6,786
1978	35.5	1,536,055	59.33	30.52	0.5144	1.0000	790,213	25,891
1977	36.5	418,814	58.90	30.12	0.5114	1.0000	214,184	7,111

UNS Electric, Inc.

Distribution Plant
Account: 362.00 Station Equipment

Dispersion: 56 - L1.5
Procedure: Vintage Group

Generation Arrangement

	December 31, 2013				Net			
Vintage	Age	Surviving Plant	Avg. Life	Rem. Life	Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1976	37.5	116,568	55.85	29.73	0.5323	1.0000	62,052	2,087
1975	38.5	12,679	59.35	29.36	0.4946	1.0000	6,271	214
1974	39.5	107,106	61.61	28.99	0.4706	1.0000	50,403	1,738
1973	40.5	381,124	57.83	28.64	0.4953	1.0000	188,768	6,591
1972	41.5	814,136	59.78	28.30	0.4734	1.0000	385,405	13,619
1970	43.5	48,160	59.05	27.64	0.4681	1.0000	22,544	816
1969	44.5	605	55.60	27.32	0.4914	1.0000	297	11
1968	45.5	750	49.27	27.01	0.5483	1.0000	411	15
1967	46.5	57,780	62.00	26.71	0.4308	1.0000	24,893	932
1966	47.5	26,021	59.26	26.41	0.4457	1.0000	11,598	439
1965	48.5	10,588	62.77	26.12	0.4161	1.0000	4,406	169
1964	49.5	14,862	63.53	25.83	0.4066	1.0000	6,043	234
1963	50.5	36,015	63.99	25.55	0.3993	1.0000	14,382	563
1962	51.5	16,558	63.29	25.27	0.3993	1.0000	6,612	262
1961	52.5	22,693	64.56	24.99	0.3872	1.0000	8,786	352
1960	53.5	7,850	57.02	24.72	0.4335	1.0000	3,403	138
1957	56.5	150	67.09	23.91	0.3564	1.0000	53	2
1956	57.5	11,156	67.65	23.64	0.3495	1.0000	3,899	165
1955	58.5	17,844	68.04	23.38	0.3436	1.0000	6,131	262
1951	62.5	9,043	70.67	22.32	0.3159	1.0000	2,856	128
1949	64.5	11	66.47	21.80	0.3279	1.0000	4	
1948	65.5	5,982	68.35	21.54	0.3151	1.0000	1,885	88
1947	66.5	3,276	73.30	21.27	0.2903	1.0000	951	45
1946	67.5	1,951	73.98	21.01	0.2840	1.0000	554	26
1945	68.5	590	74.68	20.75	0.2779	1.0000	164	8
1944	69.5	700	75.39	20.49	0.2719	1.0000	190	9
1943	70.5	25,342	75.96	20.24	0.2664	1.0000	6,752	334
1940	73.5	209	78.32	19.47	0.2486	1.0000	52	3
1938	75.5	52,634	79.74	18.96	0.2378	1.0000	12,514	660
Total	11.5	$62,380,383	56.35	46.65	0.8280	1.0000	$51,647,896	$1,107,018

UNS Electric, Inc.
Distribution Plant
Account: 362.00 Station Equipment

Age Distribution

Vintage	Age as of 12/31/2013	Derived Additions	1999 Opening Balance	Experience to 12/31/2013 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2013	0.5	6,542,156		6,542,156	1.0000	0.5000
2012	1.5	1,100,568		1,100,568	1.0000	1.5000
2011	2.5	8,630,454		8,630,453	1.0000	2.5000
2010	3.5	1,793,659		1,791,352	0.9987	3.4994
2009	4.5	7,335,959		7,332,343	0.9995	4.4998
2008	5.5	3,460,565		3,460,565	1.0000	5.5000
2007	6.5	5,198,366		5,198,366	1.0000	6.5000
2006	7.5	3,125,893		3,090,591	0.9887	7.4831
2005	8.5	197,720		178,505	0.9028	8.2571
2004	9.5	54,193		54,226	1.0006	9.5009
2003	10.5	1,534,472		1,534,488	1.0000	10.5000
2002	11.5	599,220		579,054	0.9663	11.3486
2001	12.5	870,151		863,848	0.9928	12.4674
2000	13.5	1,420,004		1,420,004	1.0000	13.5000
1999	14.5	2,335,104		2,111,358	0.9042	14.3009
1998	15.5		801,318	800,724	0.9993	15.4900
1997	16.5		2,968,575	2,831,339	0.9538	16.3210
1996	17.5		1,130,778	1,128,265	0.9978	17.5012
1995	18.5		819,798	675,452	0.8239	17.6984
1994	19.5		191,212	144,474	0.7556	16.2546
1993	20.5		1,173,817	1,221,432	1.0406	21.0476
1992	21.5		721,575	716,267	0.9926	21.4007
1991	22.5		819,826	819,767	0.9999	22.5000
1990	23.5		123,766	108,375	0.8756	23.4378
1989	24.5		1,706,368	1,251,979	0.7337	23.3943
1988	25.5		259,270	254,534	0.9817	25.4909
1987	26.5		739,800	733,676	0.9917	26.4959
1986	27.5		544,732	541,302	0.9937	27.4684
1985	28.5		110,451	97,734	0.8849	28.2120
1984	29.5		155,819	155,819	1.0000	29.5000
1983	30.5		101,661	62,672	0.6165	26.5951
1982	31.5		609,096	606,500	0.9957	31.4997
1981	32.5		1,600,193	1,582,968	0.9892	32.4620
1980	33.5		1,130,080	606,003	0.5362	31.2089
1979	34.5		397,850	395,973	0.9953	34.4345
1978	35.5		1,622,403	1,536,055	0.9468	36.1800
1977	36.5		418,834	418,814	1.0000	36.4994
1976	37.5		155,203	116,568	0.7511	34.1925

UNS Electric, Inc.

Distribution Plant

Account: 362.00 Station Equipment

Age Distribution

				Experience to 12/31/2013		
Vintage	Age as of 12/31/2013	Derived Additions	1999 Opening Balance	Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1975	38.5		13,441	12,679	0.9433	38.4150
1974	39.5		145,624	107,106	0.7355	41.3771
1973	40.5		653,111	381,124	0.5836	38.2827
1972	41.5		979,996	814,136	0.8308	40.9088
1970	43.5		75,767	48,160	0.6356	41.4816
1969	44.5		1,066	605	0.5675	38.6618
1968	45.5		10,750	750	0.0698	32.9419
1967	46.5		60,305	57,780	0.9581	46.2697
1966	47.5		67,111	26,021	0.3877	44.1116
1965	48.5		10,820	10,588	0.9786	48.1891
1964	49.5		14,862	14,862	1.0000	49.5000
1963	50.5		36,804	36,015	0.9786	50.4893
1962	51.5		21,271	16,558	0.7784	50.3130
1961	52.5		31,321	22,693	0.7245	52.0868
1960	53.5		23,180	7,850	0.3386	45.0451
1957	56.5		150	150	1.0000	56.5000
1956	57.5		11,156	11,156	1.0000	57.5000
1955	58.5		20,376	17,844	0.8757	58.3103
1951	62.5		9,043	9,043	1.0000	62.5000
1949	64.5		7,645	11	0.0014	59.0079
1948	65.5		8,482	5,982	0.7052	61.2261
1947	66.5		3,276	3,276	1.0000	66.5000
1946	67.5		1,951	1,951	1.0000	67.5000
1945	68.5		590	590	1.0000	68.5000
1944	69.5		700	700	1.0000	69.5000
1943	70.5		26,196	25,342	0.9674	70.3533
1941	72.5		1,237		0.0000	71.0000
1940	73.5		209	209	1.0000	73.5000
1938	75.5		52,634	52,634	1.0000	75.3982
Total	11.5	$44,198,483	$20,591,502	$62,380,383	0.9628	

UNS Electric, Inc.
Distribution Plant
Account: 362.00 Station Equipment

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1999	21,151,204	2,553,740	11,504		23,693,440
2000	23,693,440	1,368,634	11,927	14,668	25,064,815
2001	25,064,815	884,769		271,801	26,221,385
2002	26,221,385	634,598		108,818	26,964,801
2003	26,964,801	1,496,154		120,846	28,581,801
2004	28,581,801	459,333		(179,336)	28,861,797
2005	28,861,797	(459,333)			28,402,465
2006	28,402,465	455,107			28,857,572
2007	28,857,572	6,102,166	1,284		34,958,454
2008	34,958,454	4,853,843	377,826	43,761	39,478,232
2009	39,478,232	7,767,546	1,091,349	(1,668,173)	44,486,256
2010	44,486,256	2,166,683			46,652,939
2011	46,652,939	8,896,664	60,125	(51,213)	55,438,265
2012	55,438,265	818,009	128,477		56,127,798
2013	56,127,798	1,806,074	489,426	4,935,938	62,380,383

UNS Electric, Inc.
Distribution Plant
Account: 362.00 Station Equipment

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1999	21,151,204	2,553,740	11,504		23,693,440
2000	23,693,440	1,368,634	11,927	14,668	25,064,815
2001	25,064,815	884,769		271,801	26,221,385
2002	26,221,385	634,598		108,818	26,964,801
2003	26,964,801	1,527,623		120,846	28,613,270
2004	28,613,270	54,193		(179,336)	28,488,128
2005	28,488,128	173,623			28,661,751
2006	28,661,751	3,132,370			31,794,121
2007	31,794,121	5,344,941	1,284		37,137,779
2008	37,137,779	3,462,999	377,826	43,761	40,266,713
2009	40,266,713	7,491,011	1,329,034	(1,430,488)	44,998,202
2010	44,998,202	1,793,659			46,791,861
2011	46,791,861	8,630,454	60,125	(51,213)	55,310,976
2012	55,310,976	1,043,745	128,477		56,226,244
2013	56,226,244	1,707,627	489,426	4,935,938	62,380,383

Schedule D

UNS Electric, Inc.
Distribution Plant
Account: 362.00 Station Equipment

T-Cut: None
Placement Band: 1937-2013
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1999-2003	74.0	108.1	L1	4.17	97.8	S0.5	3.81	160.6	R1 *	3.27
2000-2004	88.4	119.3	S0	3.44	152.9	R0.5 *	2.82	172.7	R2 *	2.73
2001-2005	100.0				No Retirements					
2002-2006	100.0				No Retirements					
2003-2007	0.0	194.5	SQ *	11.77	149.9	R2.5 *	11.42	116.8	S3 *	11.32
2004-2008	26.8	66.5	L2 *	11.43	54.7	S2 *	7.58	74.3	O3 *	5.98
2005-2009	17.3	44.2	L1.5 *	4.10	44.5	L1.5 *	3.96	58.4	O3 *	3.64
2006-2010	24.4	45.5	L1.5 *	6.17	46.6	L1.5 *	5.49	63.8	O3 *	5.06
2007-2011	22.9	46.1	L1.5 *	5.45	48.7	L1 *	4.60	68.0	O4 *	4.12
2008-2012	15.1	46.1	L1.5 *	4.52	54.3	L0.5 *	5.77	73.5	O4 *	6.01
2009-2013	38.6	47.5	L1 *	10.08	84.7	O4 *	4.58	87.7	O4 *	4.28

UNS Electric, Inc.
Distribution Plant
Account: 362.00 Station Equipment

T-Cut: None
Placement Band: 1937-2013
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1999-2013	37.6	58.8	L1.5*	4.58	56.2	L1.5*	5.52	89.0	O3*	3.74
2001-2013	37.7	58.2	L1.5*	4.64	56.0	L1.5*	5.54	87.6	O3*	3.90
2003-2013	29.4	55.7	L1.5*	3.75	54.5	L1.5*	3.89	83.0	O3*	2.98
2005-2013	26.4	52.4	L1.5*	3.69	52.1	L1.5*	3.74	76.8	O3*	2.90
2007-2013	20.5	47.9	L1.5*	3.71	48.3	L1.5*	3.66	68.0	O3*	3.05
2009-2013	38.6	47.5	L1*	10.08	84.7	O4*	4.58	87.7	O4*	4.28
2011-2013	7.0	59.9	L1.5*	7.91	55.8	S1*	8.03	85.1	O3*	8.42
2013-2013	44.3	42.1	L1.5*	19.04	41.7	L2*	20.11	50.9	L2*	19.69

UNS Electric, Inc.
Distribution Plant
Account: 362.00 Station Equipment

T-Cut: None
Placement Band: 1937-2013
Hazard Function: Proportion Retired
Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1999-2000	31.2	64.0	L1 *	16.12	58.0	S0.5	14.61	106.5	O3 *	12.43
1999-2002	70.0	95.1	L1 *	4.43	84.4	S0.5	4.04	149.6	SC *	3.38
1999-2004	77.4	119.6	S0	3.94	112.1	S0.5	3.73	168.5	R1.5 *	3.50
1999-2006	87.5	138.6	R1	1.95	141.1	R1	1.96	178.8	R2.5 *	1.86
1999-2008	40.3	75.4	L1.5 *	10.43	59.1	S2 *	8.24	94.8	O3 *	5.94
1999-2010	39.6	58.2	L1.5 *	5.23	56.5	L1.5 *	5.90	91.4	O4 *	4.62
1999-2012	41.7	62.9	L1.5 *	4.28	61.7	L1.5 *	4.54	100.2	O3 *	3.14
1999-2013	37.6	58.8	L1.5 *	4.58	56.2	L1.5 *	5.52	89.0	O3 *	3.74

UNS Electric, Inc.

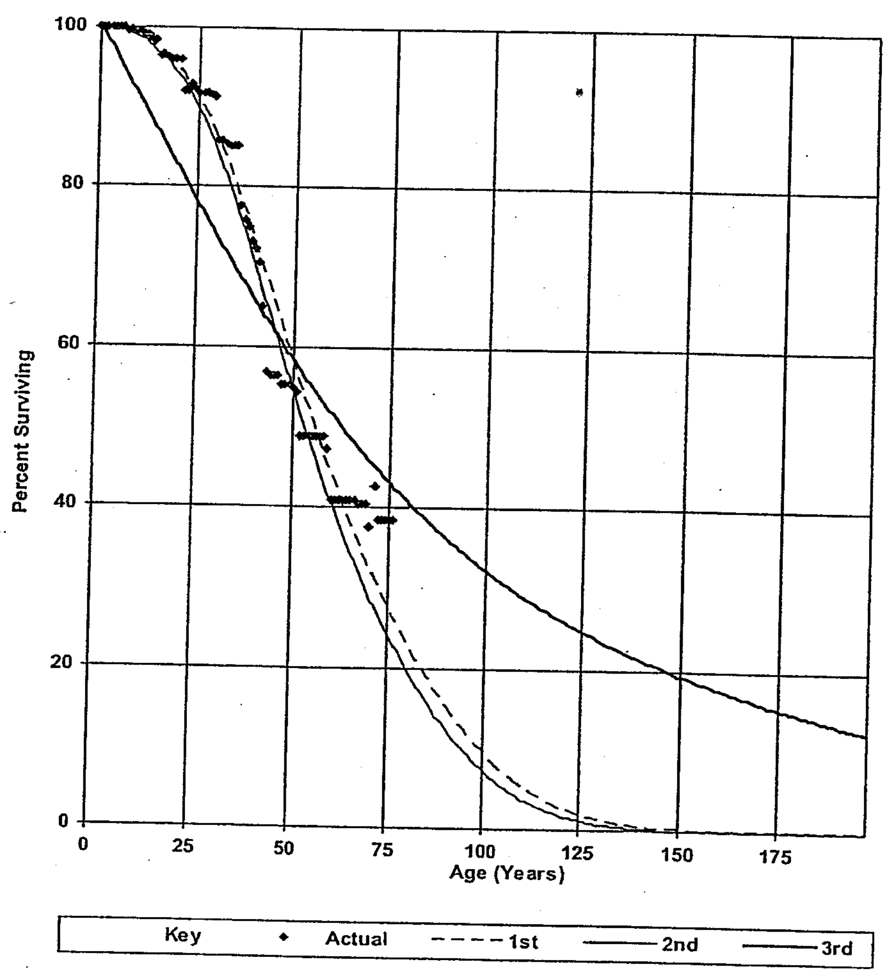
Distribution Plant

Account: 362.00 Station Equipment

T-Cut: None
Placement Band: 1937-2013 Observation Band: 1999-2013
Hazard Function: Proportion Retired
Weighting: Exposures

Graphics Analysis

1st: 58.8-L1.5 2nd: 56.2-L1.5 3rd: 89.0-O3



UNS Electric, Inc.

Distribution Plant

Account: 362.00 Station Equipment

T-Cut: None

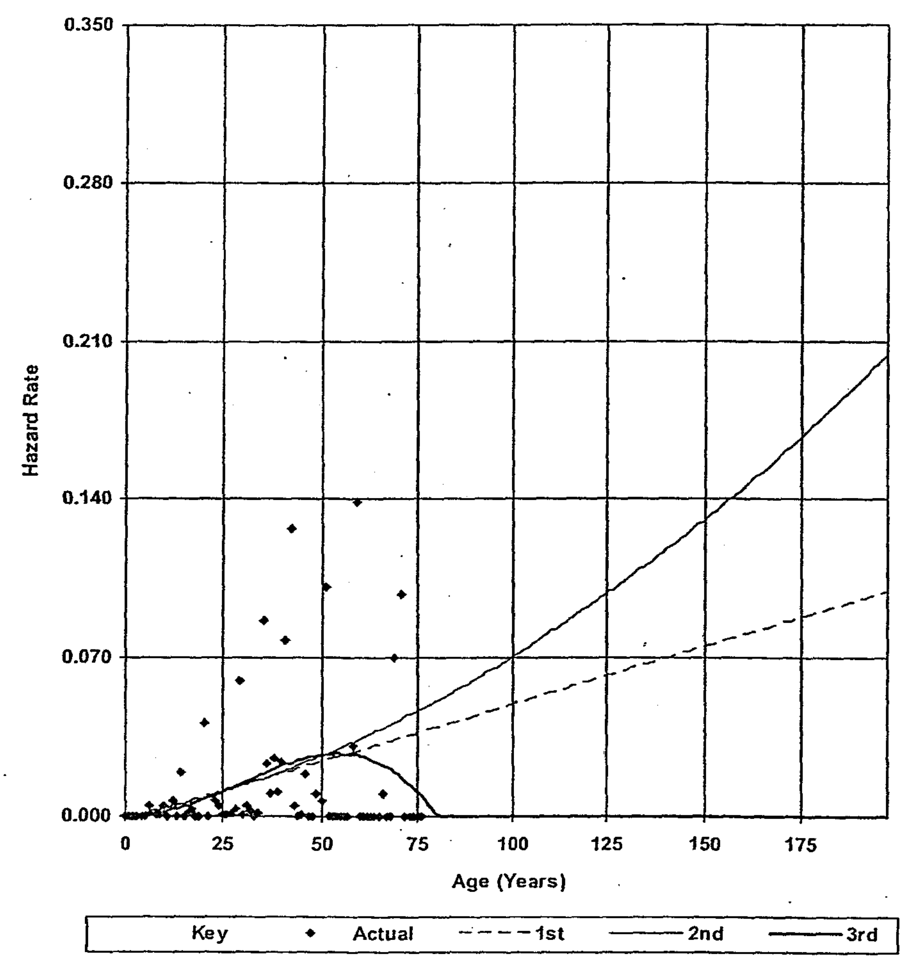
Placement Band: 1937-2013 Observation Band: 1999-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 58.8-L1.5 2nd: 56.2-L1.5 3rd: 89.0-O3



UNS Electric, Inc.

Distribution Plant

Account: 362.00 Station Equipment

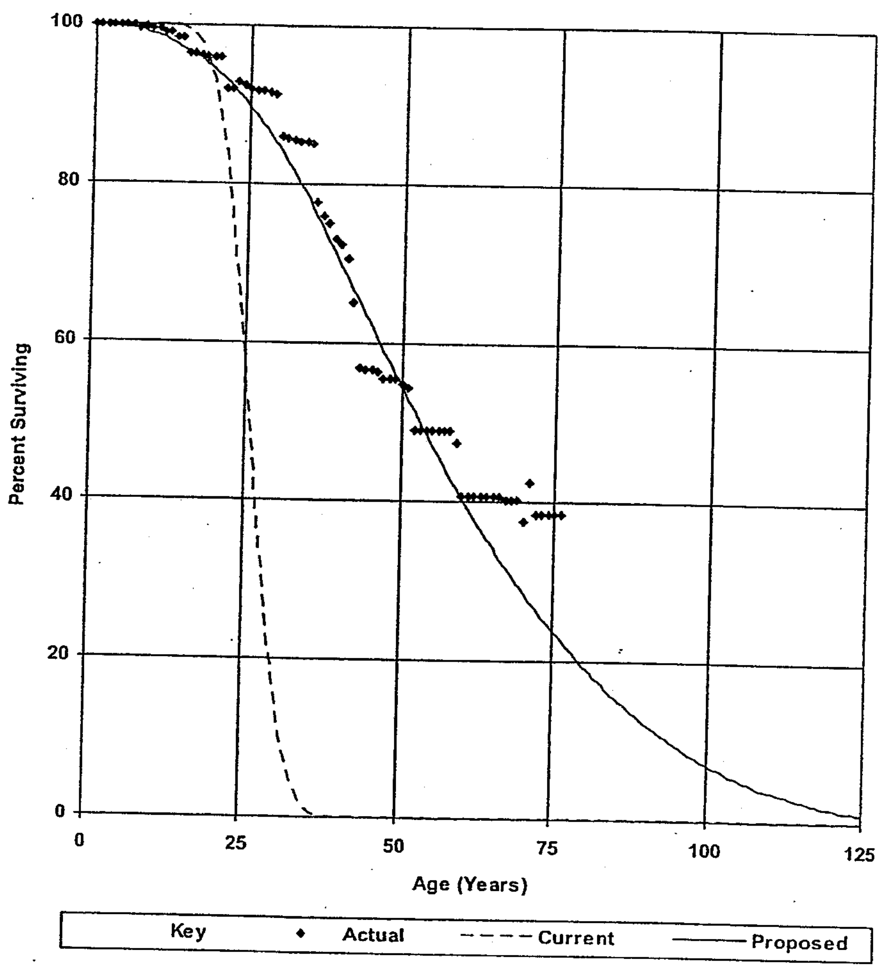
T-Cut: None

Placement Band: 1937-2013

Observation Band: 1999-2013

Current and Proposed Projection Life Curves

Current: 25.0-S4 Proposed: 56.0-L1.5



UNS Electric, Inc.

Distribution Plant

Account: 362.00 Station Equipment

Unadjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1999	11,504		0.0			0.0			0.0	
2000	11,927		0.0			0.0			0.0	
2001			0.0			0.0			0.0	
2002			0.0			0.0			0.0	
2003			0.0	0.0		0.0	0.0		0.0	0.0
2004			0.0	0.0		0.0	0.0		0.0	0.0
2005			0.0	0.0		0.0	0.0		0.0	0.0
2006			0.0	0.0		0.0	0.0		0.0	0.0
2007	1,284	45	3.5	3.5		0.0	0.0	45	3.5	3.5
2008	377,826	7,372	2.0	2.0		0.0	0.0	7,372	2.0	2.0
2009	1,091,349	35,884	3.3	2.9		0.0	0.0	35,884	3.3	2.9
2010			0.0	2.9		0.0	0.0		0.0	2.9
2011	60,125	4,500	7.5	3.1		0.0	0.0	4,500	7.5	3.1
2012	128,477	(2,705)	-2.1	2.7		0.0	0.0	(2,705)	-2.1	2.7
2013	489,426	147,950	30.2	10.5	359,021	73.4	20.3	(211,071)	-43.1	-9.8
Total	2,171,918	193,046	8.9		359,021	16.5		(165,976)	-7.6	

UNS Electric, Inc.
Distribution Plant
Account: 362.00 Station Equipment

Adjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1999	11,504		0.0			0.0			0.0	
2000	11,927		0.0			0.0			0.0	
2001			0.0			0.0			0.0	
2002			0.0			0.0			0.0	
2003			0.0	0.0		0.0	0.0		0.0	0.0
2004			0.0	0.0		0.0	0.0		0.0	0.0
2005			0.0	0.0		0.0	0.0		0.0	0.0
2006			0.0	0.0		0.0	0.0		0.0	0.0
2007	1,284	45	3.5	3.5		0.0	0.0	45	3.5	3.5
2008	377,826	7,372	2.0	2.0		0.0	0.0	7,372	2.0	2.0
2009	1,329,034	35,884	2.7	2.5		0.0	0.0	35,884	2.7	2.5
2010			0.0	2.5		0.0	0.0		0.0	2.5
2011	60,125	4,500	7.5	2.7		0.0	0.0	4,500	7.5	2.7
2012	128,477	(2,705)	-2.1	2.4		0.0	0.0	(2,705)	-2.1	2.4
2013	489,426	147,950	30.2	9.2	359,021	73.4	17.9	(211,071)	-43.1	-8.6
Total	2,409,602	193,046	8.0		359,021	14.9		(165,976)	-6.9	

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 FOR RELATED APPROVALS.)

DOCKET NO. E-04204A-15-______

EXHIBIT
UNSE-8
ADMITTED

Direct Testimony of

Kentton C. Grant

on Behalf of

UNS Electric, Inc.

May 5, 2015

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Kentton C. Grant. My business address is 88 East Broadway, Tucson, Arizona 85701.

Q. What is your position with UNS Electric, Inc. ("UNS Electric" or the "Company")?

A. I am a Vice President of UNS Electric. I also serve as Vice President and Treasurer for UniSource Energy Services ("UES"), an intermediate holding company for UNS Electric, and as Vice President of Finance and Rates for UNS Energy Corporation ("UNS Energy"), the ultimate parent company for UNS Electric in Arizona.

Q. Please describe your background and work experience.

A. I have been employed by Tucson Electric Power Company ("TEP"), a corporate affiliate of UNS Electric, since 1995. From 1995 to 2007 I served in a variety of financial roles including Senior Financial Analyst, Director of Capital Resources and Manager of Financial Planning. In 2007, I was elected Vice President of Finance and Rates for both TEP and UNS Energy Corporation. In 2010, I was elected Treasurer for both TEP and UES. In these roles I have gained extensive experience in financial forecasting, financial analysis, the structuring of financing transactions and other related activities.

Before my employment at TEP, I was employed as a staff member at the Public Utility Commission of Texas from 1984 to 1995. During this period I worked in several different capacities, including Director of the Financial Review Division. In that role, I directed staff responsible for performing financial analyses, accounting reviews and management audits of electric and telecommunications utilities. As a staff member, I also provided expert testimony on a variety of financial topics including the cost of capital, financial integrity, rate moderation and the valuation of utility properties.

I received a Master of Business Administration degree with a concentration in finance from the University of Texas at Austin, as well as a Bachelor of Science degree in Civil Engineering from Purdue University. I am also a member of the Chartered Financial Analyst ("CFA") Institute, and in 1995, I was awarded the professional designation of CFA.

Q. **What is the purpose of your direct testimony?**

A. The purpose of my testimony is to provide an overview of the Company's financial condition and to make recommendations concerning the Company's capital structure, cost of debt, and weighted average cost of capital ("WACC"). I also discuss the methods used by UNS Electric to determine fair value rate base ("FVRB") and the appropriate rate of return ("ROR") on FVRB, otherwise referred to as the fair value rate of return ("FVROR"). Further, I discuss the cost of credit support required for the Company's fuel and purchased power procurement activities, as well as the financial impact of reducing depreciation rates on UNS Electric's distribution plant. Finally, I address many of the conditions from the Fortis/UNS Energy settlement agreement that the Arizona Corporation Commission ("Commission") approved in Decision No. 74689 (August 12, 2014) that are pertinent to this rate case.

Q. **Please summarize your recommendations.**

A. I recommend a weighted average cost of capital of 7.67% based on a capital structure consisting of 52.83% common equity and 47.17% long-term debt, a cost of long-term debt of 4.66%, and a cost of common equity of 10.35% as determined by UNS Electric witness Ann E. Bulkley.

II. FINANCIAL CONDITION OF UNS ELECTRIC.

Q. Please describe the current financial condition of UNS Electric.

A. The Company is in good financial condition. UNS Electric has made substantial progress in improving its financial health since 2003, when the Arizona electric properties of Citizens Communications Company were purchased by UNS Energy. The Company currently has a healthy mix of debt and equity capital and was recently upgraded by Moody's Investors Service ("Moody's") from Baa1 to A3 (senior unsecured credit rating). This in turn has allowed UNS Electric to refinance most of its debt obligations on more favorable terms, and has also increased the amount of trade credit available to UNS Electric in the natural gas and wholesale power markets. As I discuss later in my testimony, these important benefits are fully reflected in the Company's current rate filing.

Q. What are some of the financial challenges still facing UNS Electric?

A. There are several key challenges that, if left unaddressed, could serve to reverse the recent gains made by the Company.

First and foremost, UNS Electric's retail rates do not yet reflect the costs associated with the Company's recent investment in Gila River Unit 3 ("Gila River"). In December 2014, UNS Electric purchased a 25% share of this gas-fired generating facility for $55 million. This is a substantial investment for UNS Electric, representing approximately 28% of the original cost rate base approved in the Company's last rate case. Although the Commission authorized the Company to defer up to $10.5 million of non-fuel costs associated with Gila River through April 30, 2016, pursuant to Decision No. 74911 (January 22, 2015), timely rate recognition of this facility is needed to support UNS Electric's cash flow and credit ratings.

Second, the Company's largest retail customer recently suspended operations and has sharply reduced its purchases of electrical energy from UNS Electric. The estimated impact on UNS Electric's pre-tax income and cash flow is approximately $3.5 million per year. Additionally, since this customer was also a major employer in Mohave County, this action is expected to have a spillover effect on the local economy and growth prospects in the region. This is one of the reasons why the Company is proposing an economic development rate, as described in the testimony of UNS Electric witness Dallas Dukes.

Third, as a result of significant growth in rooftop solar deployment by the Company's residential and commercial customers, the implementation of energy efficiency programs, as well as customer conservation efforts, UNS Electric is facing an erosion of its retail sales and margins. Although the lost fixed cost recovery ("LFCR") mechanism approved in the Company's last rate case is a step in the right direction, it does not provide for full fixed cost recovery and does not address the significant cost shift (and related economic incentive) that is driving the growth in solar rooftop deployment. As described in the testimony of UNS Electric witnesses Craig Jones and Dallas Dukes, the Company is proposing changes to its rate design to ensure that all customers, including those that self-generate but remain connected to the UNS Electric system, pay a reasonable share of the cost of providing safe and reliable service. From a financial perspective, it is important that the Commission address the economic issues associated with net metering and rooftop solar deployment in a timely and equitable manner.

Lastly, as described in the testimony of Company witness Dr. Ronald White, a large reduction in the depreciation rates applied to UNS Electric's distribution plant is now proposed based on the results of an updated depreciation study. While a large reduction to depreciation expense should have little impact on UNS Electric's earnings, assuming the change in depreciation rates is synchronized with the implementation of new retail rates, it would have a negative impact on the Company's operating cash flow. Because operating cash flow is a key factor considered by credit rating agencies, it is important to consider the potential impact on UNS Electric's credit ratings when evaluating the timing and magnitude of proposed depreciation changes.

III. CAPITAL STRUCTURE.

Q. Please describe the capital structure for UNS Electric as of the end of the test-year.

A. The capital structure for UNS Electric as of December 31, 2014 consisted of $170.0 million principal amount of debt and $189.9 million of common equity. After adjusting for unamortized debt issuance expenses, the debt balance as of December 31, 2014 was $169.6 million. As reflected in the following table, the Company's test-year capital structure consisted of 47.17% long-term debt and 52.83% common equity:

($ Thousands)	12/31/2014	% of Total
Debt	$169,590	47.17%
Common Equity	189,932	52.83%
Total Capital	$359,522	100.00%

Q. Do you recommend using the actual test-year capital structure for rate setting purposes?

A. Yes, I do. A 53% ratio of common equity to total capital is in line with industry norms and would help support the Company's investment-grade credit rating. It is also nearly identical to the capital structure approved in UNS Electric's last rate case.

IV. COST OF DEBT.

Q. What was UNS Electric's embedded cost of debt for the test-year?

A. As shown on page 1 of Schedule D-2 in the Company's Application, the weighted average cost of debt for UNS Electric for the test-year was 4.82%. However, the $40 million revolving credit loan balance at the end of the test year has already been refinanced with a new series of long-term debt. Additionally, both the $30 million term loan and the $50 million principal amount of 2008 Series A notes outstanding at the end of the test year will mature in August 2015. As described below, the Company has already priced a new series of long-term notes that will be issued in August 2015 to repay the $80 million of maturing debt. The Company is therefore proposing a weighted average cost of debt that reflects the cost of new debt obligations that will be outstanding at the time new rates are implemented for UNS Electric.

Q. Please describe the financing transactions that UNS Electric entered into after the test year.

A. Certainly. In March 2015, the Company marketed and priced two series of long-term notes through a private placement offering. Pursuant to a note purchase agreement between UNS Electric and participating investors, $50 million principal amount of Series B notes were issued on April 8, 2015. Proceeds from that note issuance were used to repay a $42 million balance of revolving credit loans and to fund ongoing capital expenditures. Pursuant to this same note purchase agreement, an additional $80 million principal amount of Series A notes will be issued on or before August 6, 2015. Proceeds from that issuance will be used to repay the $80 million of debt obligations maturing that same month. These financing transactions were entered into pursuant to the authority that the Commission approved in UNS Electric's most recent financing order, Decision No. 74865 (December 18, 2014).

Q. What are the terms of the new long-term notes?

A. The $50 million Series B notes have a fixed interest rate of 3.95% and mature in April 2045. The $80 million Series A notes will have a fixed interest rate of 3.22% and will mature in August 2027. As a result of a favorable interest rate environment and the Company's most recent credit rating upgrade, these are the lowest rates ever obtained by UNS Electric in a long-term note offering.

Q. What cost of debt do you recommend in this case?

A. I recommend a weighted average cost of debt of 4.66%. This cost reflects (i) the interest rates on the new 2015 Series A and Series B notes, (ii) the interest rate on the 2008 Series B notes that do not mature until 2023, (iii) the amortization of debt issuance costs, and (iv) 50% of the issuance cost amortization and commitment fees on the $100 million revolving credit facility shared with UNS Gas. The proposed treatment of debt issuance costs and revolving credit commitment fees is consistent with Commission treatment of such costs in previous UNS Electric rate decisions.

Q. How does this cost of debt compare with the cost approved in UNS Electric's last rate case?

A. It is significantly lower. A 5.97% cost of debt was approved in the Company's last rate order (Decision No. 74235 (December 31, 2013)). Even though UNS Electric now has a much longer weighted average debt maturity, the cost of debt has been significantly reduced as a result of a favorable interest rate environment and an improved credit rating.

V. WEIGHTED AVERAGE COST OF CAPITAL.

Q. What is the WACC for UNS Electric?

A. Based on the test year capital structure for UNS Electric, a 4.66% cost of long-term debt, and a 10.35% cost of common equity recommended by UNS Electric witness Ann Bulkley, the Company's WACC is 7.67%. This value is calculated as follows:

	% of Capital Structure	Component Cost	Weighted Average Cost
Common Equity	52.83%	10.35%	5.47%
Long-Term Debt	47.17%	4.66%	2.20%
Total	100.00%		7.67%

VI. FAIR VALUE RATE BASE AND FAIR VALUE RATE OF RETURN.

Q. What value for fair value rate of return ("FVROR") is UNS Electric proposing in its rate application?

A. As discussed in the Direct Testimony of UNS Electric witness Ann Bulkley, the Company proposes a FVROR of 6.22%. Although the Company can justify a higher value for the FVROR, as Ms. Bulkley discusses in her pre-filed direct testimony, the Company requested that Ms. Bulkley apply a ROR equal to only one-half of the real risk-free rate to the fair value increment of rate base (the difference between original cost rate base ("OCRB") and FVRB).

Q. How did UNS Electric calculate FVRB for the purposes of this filing?

A. UNS Electric relied on the approach traditionally adopted by the Commission, using the average of OCRB and reconstructed cost new less depreciation rate base ("RCND"), as those terms are defined in the Commission's rules, as the basis for calculating the Company's FVRB.

As discussed in Ms. Bulkley's testimony, this value for FVRB is also supported by a market-based approach to fair value.

VII. COST OF CREDIT SUPPORT FOR FUEL AND PURCHASED POWER PROCUREMENT.

Q. Does UNS Electric incur credit-related costs to support the procurement of natural gas and wholesale power for retail customers?

A. Yes. In addition to financing temporary under-collections of fuel and purchased power costs under the Company's Purchased Power and Fuel Adjustment Clause ("PPFAC"), UNS Electric must also provide credit support to wholesale suppliers from whom these purchases are made. This credit support may either take the form of a letter of credit issued by a creditworthy bank, a deposit of cash collateral in an escrow account, or under some circumstances a pre-payment of amounts owed to the supplier. Credit support is often required to provide assurance to a wholesale counter-party that UNS Electric will perform its obligation to purchase natural gas or wholesale power as specified by contract.

Q. Under what situations may wholesale credit support be required?

A. It is customary for participants in the wholesale gas and power markets to set a credit limit for each counter-party with whom it conducts business. Larger credit lines are typically extended to large and highly-rated market participants, while credit lines are typically much lower for small and mid-sized companies or those having weaker credit ratings. When the credit exposure to a counter-party exceeds the specified credit limit, a request for credit support is made. From the standpoint of a seller of natural gas or wholesale power, credit exposure to a contracted buyer is typically defined as the sum of: (i) the receivable balance due from the buyer; and (ii) the mark-to-market value (positive or negative) of future sales specified under the contract.

In the case of UNS Electric, requests for credit support are received from sellers of natural gas and wholesale power whenever their credit exposure to the Company exceeds the credit limit they have assigned to UNS Electric. Although credit limits may be negotiated when a new business relationship is being established or when a change in credit ratings occurs, the decision to extend credit is solely at the discretion of the seller.

Q. Is wholesale credit support needed to facilitate UNS Electric's energy hedging program?

A. Yes. UNS Electric's energy hedging program involves the purchase of natural gas and wholesale power in the forward energy markets in order to stabilize the cost of energy provided to UNS Electric's customers. As discussed above, changes in the market value of forward energy contracts can create a need for wholesale credit support.

Q. What level of credit support has UNS Electric been required to provide?

A. Historically, the Company has had to provide considerable credit support due to previously lower credit ratings and less stable market conditions for natural gas and wholesale power. In 2009, during a period of rapidly declining natural gas and wholesale power prices, the Company had to provide as much as $30 million in credit support. In the Company's last rate case, the average level of credit support during the test-year had fallen to $5.6 million. During the current test-year ending December 31, 2014, UNS Electric had only one letter of credit outstanding in the amount of $150,000 to support natural gas and wholesale power procurement. This lower level of required credit support is due in large part to the improvement in UNS Electric's credit rating.

Q. How were credit support costs addressed in UNS Electric's last two rate orders?

A. In Decision Nos. 71914 (September 30, 2010) and 74235, they were included in the Company's non-fuel revenue requirement as an adjustment to operating expense.

Q. What is your recommendation concerning the recovery of wholesale credit support costs by UNS Electric?

A. Since these costs are highly variable and directly related to UNS Electric's fuel and purchased power procurement, I have previously recommended that they be recovered through the Company's PPFAC. However, in light of past Commission treatment of these costs, I am recommending that they be included in rates as an adjustment to test-year operating expense. Since the annual cost of a letter of credit is currently 1.0% for UNS Electric, and a single $150,000 letter of credit was outstanding during the test year, the adjusted test-year cost of credit support is only $1,500.

VIII. CHANGE IN DEPRECIATION RATES.

Q. Under cost of service regulation, how does a change in depreciation rates affect a Company's financial metrics?

A. As long as the change is fully reflected in a Company's cost of service and revenue requirement, and the change is synchronized with the implementation of new retail rates, there should be no material effect on a regulated Company's earnings. However, since depreciation is a non-cash expense, the change in revenues attributable to a change in depreciation does impact a Company's operating cash flow. For example, if a $10 million reduction in non-cash depreciation expense causes a $10 million reduction in operating revenues, a Company's pre-tax cash flow would decrease by $10 million.

Q. Is the Company proposing a significant change to its plant depreciation?

A. Yes. Based on an updated depreciation study referenced in the testimony of UNS Electric witness Dr. Ronald White, the Company is proposing to lower the composite depreciation rate on distribution plant from 3.97% to 1.39%.

Q. What financial impact would this change have on UNS Electric?

A. It would reduce the Company's annual depreciation expense and non-fuel revenue requirement by approximately $9 million. Assuming a 40% marginal income tax rate would apply to the change in revenues and taxable income, a $9 million reduction to the Company's non-fuel revenue requirement would produce a $5 million after-tax reduction to operating cash flow. To put this value into perspective, $5 million represents approximately 12% of the Company's test-year operating cash flow of $43 million.

Q. Is operating cash flow a key factor considered by credit rating agencies?

A. Yes. As noted in a recent credit opinion from Moody's, dated March 2, 2015, the ratio of operating cash flow to total debt is one of key factors that will determine future credit ratings for UNS Electric. Since the Company incurred an additional $40 million of debt in late 2014 to fund a portion of the Gila River purchase and other capital expenditures, representing a 30% increase in total debt, it is important from a credit rating perspective that operating cash flow increase as well.

Q. What do you recommend with respect to the change in depreciation rates for UNS Electric?

A. If the Company's rate application is approved largely as filed, UNS Electric'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 flow, I would recommend that the change in depreciation rates for the Company's distribution plant be implemented over two rate cases instead of all at once, with approximately one-half of the change being implemented in this rate case and the remaining half implemented in UNS Electric's next rate case. Although the Company would continue to over-depreciate its distribution plant for a temporary period of time, customers would benefit from the additional depreciation expense in the next rate case as a result of a higher balance of accumulated depreciation. In combination with other expenses that naturally increase over time, this approach could help smooth future rate increases for UNS Electric and its customers.

IX. COMPLIANCE WITH FORTIS MERGER CONDITIONS.

Q. Mr. Grant, are you the witness that will address the rate case-related conditions in the Fortis/UNS Merger settlement agreement?

A. I will address most of the merger conditions that are relevant to this rate case. Mr. Terry Nay addresses Condition 28 regarding best efforts to maintain or improve quality of service and Mr. Dallas Dukes addresses Condition 62 related to service functions that are performed for UNS Electric by Fortis Inc. ("Fortis), UNS Energy or TEP.

Q. In Condition 5 of the settlement conditions approved by Decision No. 74689, Fortis, UNS Energy and the Regulated Utilities (including UNS Electric) agreed that they will not seek recovery of or on any acquisition premium or goodwill amount in any future rate proceeding. Can you confirm that UNS Electric is not seeking such recovery?

A. Yes, UNS Electric is not seeking such recovery. Moreover, UNS Electric ratepayers will not be responsible in any manner for recovery of any acquisition premium, as required by Condition 5.

Q. In Condition 6, the Companies agreed that Fortis shall not allocate any Fortis specific costs to the Regulated Utilities (including UNS Electric) for possible recovery in a future rate proceeding for five years after closing. Can you confirm that UNS Electric is not seeking such recovery in this rate case?

A. Yes, our revenue requirement does not include any Fortis specific costs.

Q. In Condition 7, Fortis, UNS Energy and the Regulated Utilities agreed that they will not pass any costs of the shareholder litigation related to the merger to ratepayers. Does the revenue requirement include any shareholder litigation costs?

A. No, it does not.

Q. In Condition 8, Fortis, UNS Energy and the Regulated Utilities agreed that they would not seek recovery of or on the transaction and transition costs associated with the merger. Does the revenue requirement include any such costs?

A. No, it does not.

Q. Condition 8 also precludes recovery of any Change of Control and Retention payments related to the merger. Can you confirm that UNS Electric is not seeking any recovery of those payments?

A. Yes, the Company is not seeking any such recovery and its ratepayers will not bear the cost of any of such payments.

Q. Condition 9 provides that Fortis shall hold the UNS Electric's ratepayers harmless from the impacts of any fluctuations in foreign exchange rates and any incremental taxes arising from its international ownership structure. Does the revenue requirement include any such impacts?

A. No, the revenue requirement does not include impacts of any fluctuations in foreign exchange rates and any incremental taxes arising from its international ownership structure.

Q. With respect to Condition 10, has Fortis made an acquisition since the approval of the Fortis/UNS Energy merger that has had any material adverse impact on UNS Electric?

A. No, it has not.

Q. With respect to Condition 11, can you confirm that the revenue requirement in this case does not include any increase in the total compensation of the Senior Management Personnel?

A. The revenue requirement does not include any such increase. The eleven executive officers of UNS Energy as of August 12, 2014, has been reduced to 10 due to the retirement of Paul Bonavia. Therefore, pursuant to Condition 11, the portion of the compensation for those Senior Management Personnel that is allocable to UNS Electric has been reduced.

Q. With respect to Condition 12, has Fortis completed any merger or acquisition within the United States since the approval of the Fortis/UNS Energy merger?

A. No, it has not.

Q. In Condition 13, Fortis, UNS Energy and the Regulated Utilities agreed that the goodwill and transaction costs of the Fortis/UNS Energy transaction would be excluded from the rate base, expenses and capitalization in the determination of rates and earned returns of UNS Electric. Can you confirm that the rate base, expenses and capitalization excludes the goodwill and transaction costs of the merger?

A. Yes, the revenue requirement, which incorporates those elements of ratemaking, does not include those items.

Q. Pursuant to Condition 15, have UNS Energy and the Regulated Utilities prepared a final schedule of the external costs to achieve the merger?

A. Yes, they have. I can confirm that the revenue requirement sought in this docket 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 acquisition.

Q. As contemplated in Condition 17, is the proposed capital structure in this docket separate from that of Fortis?

A. Yes, it is. As noted above, we are proposing to use UNS Electric's actual capital structure in this rate case.

X. SUMMARY OF SCHEDULES.

Q. Please describe Schedule D in the Company's Application.

A. Schedules D-1 through D-4 contain the Company's actual and proposed capital structure, cost of debt and WACC for the test year ended December 31, 2014. These schedules also include a projected capital structure, cost of debt and WACC for the twelve months ending December 31, 2015.

Q. Please describe Schedule F in the Company's Application.

A. Schedule F consists of four parts, Schedules F-1 through F-4.

Schedule F-1 contains a summary income statement for the test year ended December 31, 2014. This same information is presented on a projected basis for the twelve months ending December 31, 2015. The projected year information is also presented assuming that the requested rate increase was implemented on January 1, 2015.

Schedule F-2 contains a summary cash flow statement for the test year ended December 31, 2014. This same information is presented on a projected basis for the twelve months ending December 31, 2015. The projected year information is also presented assuming that the requested rate increase was implemented on January 1, 2015.

Schedule F-3 contains information on the Company's capital investments during the test year ended December 31, 2014. The same information is presented on a projected basis for calendar years 2015, 2016 and 2017.

Schedule F-4 contains a description of key forecast assumptions used in preparing the projected information appearing in Schedules F-1 through F-3.

Q. Please comment on the projected information appearing in Schedules F-1 and F-2.

A. The financial projections that assume a continuation of current rates through April 2016 were taken from a base case financial forecast prepared for UNS Electric. It should be noted that this forecast is based on numerous assumptions regarding sales growth, wholesale energy prices, natural gas prices, operating and capital expenditure levels, and other factors that are subject to change over time. Additional financial projections are provided in Schedules F-1 and F-2 that assume implementation of the Company's requested rate increase as of January 1, 2015. These additional projections are included for purposes of complying with the Commission's rate filing requirements. Since the Company will not be able to change its retail rates until it is ordered to do so by the Commission, projections assuming that the requested rates were implemented in January 2015 are of limited analytical value.

Q. Does this conclude your Direct Testimony?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - INTERIM CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
VACANT

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

Rebuttal Testimony of

Kentton C. Grant

on Behalf of

UNS Electric, Inc.

January 19, 2016

UNSE-9
ADMITTED

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I. INTRODUCTION.

Q. Please state your name and business address.

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

Q. Did you file Direct Testimony in this proceeding?

A. Yes.

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

A. My Rebuttal Testimony is filed on behalf of UNS Electric, Inc.

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

A. My Rebuttal Testimony addresses the testimony of four witnesses. With respect to the testimony of Dr. J. Randall Woolridge filed on behalf of The Alliance for Solar Choice ("TASC"), I take issue with his use of a hypothetical capital structure for UNS Electric. With respect to the testimony of Robert B. Mease filed on behalf of the Residential Utility Consumer Office ("RUCO"), I discuss the shortcomings of the methodology he used to calculate the rate of return on fair value rate base, which is commonly referred to as the fair value rate of return ("FVROR"). Lastly, I address the cost of equity and FVROR recommendations of Commission Staff ("Staff") witnesses Elijah Abinah and Donna M. Mullinax.

II. REBUTTAL OF TASC WITNESS DR. J. RANDALL WOOLRIDGE.

Q. What capital structure does Dr. Woolridge use in his cost of capital analysis?

A. Dr. Woolridge uses a hypothetical capital structure consisting of 50% common equity and 50% long-term debt. His only explanation for using this capital structure, instead of the Company's actual capital structure consisting of 52.83% common equity and 47.17% long-term debt, is that UNS Electric "has a higher common equity ratio" than the two proxy groups of electric utilities listed in Exhibit JRW-4 attached to his direct testimony. (See page 13 of Woolridge Direct Testimony, lines 15-17.)

Q. Is there any reasonable basis for using a hypothetical capital structure for UNS Electric?

A. No. The Company's capital structure is nearly identical to that adopted by the Commission in UNS Electric's last rate case (52.6% common equity), and it is also comparable to that approved by the Commission in Arizona Public Service Company's last rate case (53.9% common equity). Additionally, the percentage of common equity in UNS Electric's capital structure is only slightly higher than the median value of common equity in the two proxy groups cited by Dr. Woolridge (47.8% and 49.3%, respectively), and it falls well within the range of values for both groups. By substituting his hypothetical capital structure for the Company's actual capital structure, Dr. Woolridge is effectively assigning a 4.66% cost of debt to a portion of the common equity invested by UNS Electric in plant and equipment used to serve customers.

Q. Is there a logical explanation as to why UNS Electric would have more common equity in its capital structure relative to the median value for each of the proxy groups cited by Dr. Woolridge?

A. Yes. As discussed in the Rebuttal Testimony of UNS Electric witness Ann Bulkley, the common equity ratios cited by Dr. Woolridge are based on consolidated holding company financials, and not on utility stand-alone financials. Second, and more importantly, UNS Electric is much smaller than all of the publicly traded companies included in each of the proxy groups, and the Company's credit rating is also higher than most of the companies in the two proxy groups. As may be seen in Exhibit JRW-4 attached to his testimony, the median credit rating assigned by Moody's Investors Service to the electric utilities in each of the proxy groups is "Baa1". By contrast, UNS Electric has a Moody's credit rating of "A3", which is one notch higher than Baa1. By deploying less debt in its capital structure, UNS Electric enjoys a slightly higher credit rating, resulting in more favorable debt pricing and improved access to credit, benefits which ultimately accrue to the Company's customers.

Q. Is the capital structure of UNS Electric referenced in the 2014 Commission order approving the merger of UNS Energy Corporation and Fortis Inc.?

A. Yes. In the Settlement Agreement approved by the Commission in Decision No. 74689 (August 12, 2014), Condition No. 16 restricts the ability of UNS Electric to pay dividends for a period of five years or until its common equity ratio reaches 50%. Although it is not determinative for rate making purposes, that decision implies that a common equity ratio of 50% is the minimum amount of equity deemed by the Commission to be reasonable for UNS Electric.

Q. Should the Commission reject the use a hypothetical capital structure for UNS Electric?

A. Yes, for the reasons described above.

III. <u>REBUTTAL OF RUCO WITNESS ROBERT B. MEASE.</u>

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

A. As described in his Executive Summary, lines 30-36, he subtracts an inflation adjustment of 1.35% from his recommended cost of capital of 6.61% to arrive at a FVROR of 5.26%. In support of this approach, he cites two Commission rate orders involving UNS Electric and its sister company, UNS Gas, Inc. On page 32 of his testimony, he also discusses the need to eliminate a "double-counting" of inflation that would otherwise supposedly occur.

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

A. No, I do not. Although it has been adopted by the Commission on two occasions in the past, it is a methodology that is not practically or theoretically sound. It also conflicts with the methodology approved by the Commission in more recent rate cases - as well as the methodology proposed by UNS Electric and by Commission Staff in this docket.

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

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

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

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

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

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

Q. Please explain.

A. As an example, the inflation expectations calculated by Mr. Mease over the period 2009-2015 ranged from a low of 0.48% in 2015 to a high of 2.23% in 2011. (See Schedule RBM-4 attached to his testimony.) Even though this range of expected inflation is modest by historical standards, the resulting FVROR would be very different if either of those values had been selected in lieu of the 1.35% average rate used by Mr. Mease. The following table illustrates the impact of using these different rates on the FVROR and revenue requirement for UNS Electric, based on the Company's proposed WACC and FVRB:

	Low Rate from RBM-4	Avg. Rate from RBM-4	High Rate from RBM-4
WACC	7.67%	7.67%	7.67%
Inflation Adjustment	-0.48%	-1.35%	-2.23%
FVROR	**7.19%**	**6.32%**	**5.44%**
x FVRB ($000s)	$355,720	$355,720	$355,720
Return ($000s)	**$25,562**	**$22,482**	**$19,337**
x Gross-Up Factor	1.6084	1.6084	1.6084
Return & Taxes ($000s)	**$41,114**	**$36,159**	**$31,101**

As illustrated above, the impact of even minor changes in expected inflation can produce very different results in terms of the FVROR and overall revenue requirement. During periods of low inflation or deflation, the methodology used by Mr. Mease would produce a large return premium for most utilities. Conversely, during periods of high inflation, his proposed methodology would impose severe return penalties on most utilities, even if the FVRB exceeded the OCRB by a wide margin. Since having a FVRB in excess of the OCRB is a plus in terms of lowering perceived investor risk and the cost of capital to a utility, the potential for a significant FVROR penalty is something the Commission should be aware of in assessing the methodology proposed by Mr. Mease.

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

A. No, it does not. As illustrated in the table above, subtracting an inflation adjustment of 1.35% from the Company's 7.67% WACC would result in a FVROR of 6.32%. This value is higher than the FVROR of 6.22% proposed by UNS Electric. However, for the reasons described above, the Company does not support the methodology used by Mr. Mease in calculating the FVROR.

Q. What FVROR does Mr. Mease recommend for UNS Electric?

A. As mentioned earlier, he recommends a FVROR of 5.26%. The reason it is lower than the 6.32% value referenced above is that his WACC is based on a cost of equity of only 8.35% (200 basis points lower than the value proposed by UNS Electric). Company witness Ann Bulkley addresses the cost of equity analysis of Mr. Mease in her Rebuttal Testimony.

IV. <u>REBUTTAL OF STAFF WITNESSES ELIJAH ABINAH AND DONNA H. MULLINAX.</u>

Q. What did Staff recommend regarding the FVROR for UNS Electric?

A. Staff witness Elijah Abinah recommends applying a rate of return ("ROR") of 0.5% to the fair value increment of rate base, which represents the difference between the Company's FVRB and OCRB. Staff witness Mullinax then used this rate, along with Staff's recommended values for FVRB, OCRB, and the WACC to arrive at a FVROR of 5.60%. This calculation is shown in Attachment DHM-2, lines 22-26 of Schedule D, attached to the testimony of Ms. Mullinax.

Q. Did Ms. Mullinax use the same methodology proposed by UNS Electric in calculating the FVROR?

A. Yes. Although some of the input values are different from those proposed by the Company, namely the values for OCRB, FVRB, the cost of equity, and the ROR on the fair value increment of rate base, the method she used to calculate the FVROR is the same as proposed by the Company.

Q. Did you find any mathematical errors in Staff's calculation of the FVROR?

A. Yes. The relative weightings for long-term debt, common equity and the fair value increment of rate base shown in column C, lines 23-25, of Attachment DHM-2 (Schedule D) were incorrect. Had Ms. Mullinax used the correct weightings, Staff's FVROR would have been slightly higher at 5.63%, as shown below:

	Balance	% Total	Cost	Wtd. Cost
OCRB L-T Debt	$127,451	36.01%	4.66%	1.68%
OCRB Equity	$142,738	40.33%	9.50%	3.83%
Fair Value Increment	$83,707	23.65%	0.50%	0.12%
	$353,896	100.00%		5.63%

Q. What is the Company's position with respect to the 9.5% cost of equity and 0.5% return on the fair value increment of rate base recommended by Staff?

A. Both of these values are significantly lower than what the Company proposed, and what can be reasonably justified based on the analysis of UNS Electric witness Ann Bulkley. However, they are consistent with the values UNS Electric stipulated to as part of a comprehensive settlement agreement in the Company's last rate case. As long as the overall revenue increase and rate design approved for UNS Electric provides the Company with a reasonable opportunity to actually earn a 9.5% return on equity, the Company would not be opposed to the adoption of Staff's recommended values.

Q. Does this conclude your Testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

Rejoinder Testimony of

Kentton C. Grant

on Behalf of

UNS Electric, Inc.

February 29, 2016

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

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

Q. Did you file Direct and Rebuttal Testimony in this proceeding?

A. Yes.

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

A. My Rejoinder Testimony is filed on behalf of UNS Electric, Inc.

Q. Which Intervenors' testimony do you address in your Rejoinder Testimony?

A. My Rejoinder Testimony addresses the testimonies of Robert B. Mease and Jeffrey Michlik filed on behalf of the Residential Utility Consumer Office ("RUCO"). Specifically, I discuss the Company's position with respect to Mr. Mease's revised estimates for the cost of equity and the rate of return on fair value rate base, which is commonly referred to as the fair value rate of return ("FVROR"). Additionally, I address his offer to consider recommending a 9.50% cost of equity and the adoption of Staff's FVROR, subject to UNS Electric limiting its rate increase no more than $15.1 million. With respect to Mr. Michlik's testimony, I reiterate the Company's earlier response to his rejection of UNS Electric's proposed property tax deferral, as well as his treatment of the costs that will be incurred by UNS Electric in its appeal of property tax values for Gila River Unit 3.

II. **<u>RESPONSE TO SURREBUTTAL TESTIMONY OF RUCO WITNESS ROBERT B. MEASE.</u>**

Q. Did Mr. Mease revise his recommended cost of equity and FVROR in his Surrebuttal Testimony?

A. Yes. Mr. Mease revised his original cost of equity estimate of 8.35% to an updated value of 9.13%. Consequently, the weighted average cost of capital (WACC) recommended by Mr. Mease increased from 6.61% to 7.02%. He then subtracted an inflation rate of 1.54%, revised upward from the previous rate of 1.35%, to arrive at a FVROR 5.48%. The following table summarizes the changes made to the WACC and FVROR in Mr. Mease's Surrebuttal Testimony:

	Direct Testimony	Surrebuttal Testimony
WACC	6.61%	7.02%
Inflation Adjustment	-1.35%	-1.54%
FVROR	5.26%	5.48%

Q. What is the Company's position with respect to Mr. Mease's revised cost of equity and FVROR?

A. As described in the Rejoinder Testimony of UNS Electric witness Ann Bulkley, the revised estimate of 9.13% for the Company's cost of equity is still too low. Additionally, UNS Electric still takes issue with the methodology used by Mr. Mease in calculating his recommended FVROR. Although this methodology was adopted several years ago in a prior rate order for UNS Electric, the use of an explicit inflation adjustment to derive the FVROR is seriously flawed from both a theoretical and practical perspective.

Q. Did Mr. Mease express a willingness to recommend a higher cost of equity and the adoption of Staff's FVROR?

A. Yes. On page 21 of his Surrebuttal Testimony, lines 4-6, Mr. Mease states that RUCO would consider recommending Staff's cost of common equity of 9.50% provided "the overall revenue requirement is not greater than $15.1 million." Additionally, on page 22, lines 15-20, Mr. Mease references RUCO's potential acceptance "of the cost of equity and fair value adjustment." Although he does not explicitly reference the 5.63% FVROR recommended in Staff's Surrebuttal Testimony, he implies that RUCO would be willing to recommend that value if the Company's revenue increase is capped at $15.1 million.

Q. How was the value of $15.1 million derived by RUCO?

A. While it was not explicitly laid out in RUCO's Surrebuttal Testimony, it is my understanding that RUCO subtracted an additional $260,000 of operating expenses from the $15,360,000 non-fuel revenue increase recommended in Staff's Surrebuttal Testimony. Staff's revised non-fuel revenue increase is discussed in the Surrebuttal Testimony of Staff witness Donna H. Mullinax (see page 5, lines 5-9, and Attachment DHM-1, line 6). As discussed by Ms. Mullinax, Staff's revised rate increase of $15.4 million resulted from a number of relatively minor adjustments that increased the overall non-fuel revenue deficiency to $18.5 million from Staff's original value of $18.1 million. Based on the recommendation of Staff witness Barbara Keane, the $18.5 million revenue deficiency was then reduced by $3.1 million due to the revised treatment of the deferred costs associated with Gila River Unit 3.

Q. What is the Company's position with respect to the $15.1 million rate increase referenced by Mr. Mease?

A. While UNS Electric does not agree in principle with the additional operating expense adjustments recommended by RUCO, the Company would be willing to stipulate to a

$15.1 million non-fuel revenue increase, and the related treatment of deferred Gila River Unit 3 costs, as long as the Company is provided with a reasonable opportunity to actually earn a 9.50% return on equity. This means that the rate design approved for UNSE must actually be capable of generating the targeted level of non-fuel revenues, setting aside normal variations due to weather conditions and sales mix. From the Company's perspective, continued reliance on an outdated rate design, coupled with a continuation of the current net metering rules, would not give UNS Electric a reasonable opportunity to earn its allowed return on equity.

III. RESPONSE TO SURREBUTTAL TESTIMONY OF RUCO WITNESS JEFFREY MICHLIK.

Q. Does Mr. Michlik still reject the Company's proposed property tax deferral described in the Direct Testimony of UNS Electric witness Jason Rademacher?

A. Yes.

Q. Does Mr. Michlik also continue to propose that UNS Electric forego future rate recovery of 50% of the costs that will be incurred to appeal property tax values for Gila River Unit 3?

A. Yes.

Q. Has the Company's position changed with respect to the proposed property tax deferral and future rate recovery of 100% of the costs of appealing property tax values for Gila River Unit 3?

A. No. UNS Electric still supports these proposals for full cost recovery. The rationale for the Company's position is described in the Rebuttal Testimony of UNS Electric witness Jason Rademacher. Additionally, it should be noted that from a financial perspective, a rejection of UNS Electric's proposals for property tax recovery would add yet another obstacle in the Company's effort to actually earn its allowed return on equity. Although the Company is accustomed to managing its costs carefully in order to earn its cost of capital, future changes in property tax rates are clearly beyond the control of UNS Electric, and the costs required to appeal the property tax valuation for a power plant can be quite large and often fall outside of an historical test year used in the rate setting process.

Q. Does this conclude your Testimony?

A. Yes, it does.

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 FOR RELATED APPROVALS.

DOCKET NO. E-04204A-15-______

Direct Testimony of

David J. Lewis

on Behalf of

UNS Electric, Inc.

May 5, 2015

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is David J. Lewis. My business address is 88 East Broadway Blvd., Tucson, Arizona 85701.

Q. What is your position with UNS Electric, Inc. ("UNS Electric" or the "Company")?

A. I am the Manager of Revenue Requirements for UNS Energy Corporation ("UNS Energy"), a wholly owned subsidiary of Fortis Inc. ("Fortis"). I am responsible for monitoring and determining revenue requirements for all the regulated subsidiaries of UNS Energy, including UNS Electric, Inc. ("UNS Electric" or the "Company").

Q. Please describe your education and experience.

A. I hold a Bachelor of Science in Business Administration, a Master's of Business Administration and a Master's of Science in Accountancy. I have over 13 years' experience within the utility industry.

Prior to working for UNS Energy, I was employed by Green Valley Water Company as the principal accountant reporting directly to the Controller.

Before then, I was the business support analysis for Raytheon Missile Systems NAPI facility in Farmington, New Mexico.

II. SUMMARY.

Q. What is the purpose of your Direct Testimony?

A. My testimony is in support of the Company's rate case filing. I am sponsoring the historical information for the twelve month period ending December 31, 2014, (the "Test Year"), presented on the following schedules:

- A-1, A-2 and A-5
- B-1 through B-5
- C-1 and C-2
- E-1 through E-9

I will also be supporting in my direct testimony the pro forma adjustments made to the Test-Year on Schedules B-2 and C-2. Specifically, I will be sponsoring the rate base pro forma adjustments on Schedule B-2 listed below:

- Acquisition Discount
- Asset Retirement Obligation
- Working Capital

Additionally, I will be sponsoring Schedules C-1, C-2 and C-3, and the pro forma accounting adjustments reflected on Schedules C listed below:

- Non-Retail Revenue and Purchased Power
- Purchased Power and Fuel Adjustment -
- Renewable Energy Standard & Tariff ("REST") and Demand-Side Management ("DSM")
- Payroll Expense
- Payroll Tax Expense
- Pension and Benefits

- Post Retirement Medical
- Rate Case Expense
- Bad Debt Expense
- Lost Fixed Cost Revenue
- Depreciation and Amortization Expense Annualization
- Incentive Compensation
- Injuries and Damages
- Membership Dues
- Gila O&M Normalization
- Outage Normalization

III. SUMMARY OF SCHEDULES.

A. <u>"A" Schedules.</u>

Q. Please describe the information contained on summary Schedule A-1.

A. Schedule A-1 provides a summary of the increase in revenue requirement that the Company is requesting. Lines 1 through 8 of Schedule A-1 present the data used in determining the Company's revenue requirement. The data presented pursuant to three valuation methodologies: (1) original cost rate base ("OCRB"); (2) reconstruction cost new less depreciation ("RCND"); and (3) fair value rate base ("FVRB"). FVRB is determined by adding together OCRB and RCND rate base amounts and dividing that total by two. This gives equal weight to both methods when determining the fair value amount. This method of determining the fair value is consistent with prior Arizona Corporation Commission ("ACC" or "Commission") practice.

Q. Please describe the information contained on Schedule A-2.

A. Schedule A-2 presents a summary of the results of operations for the Test Year and the two prior calendar years, compared with the projected year. Lines 1-16 of Schedule A-2 set forth the summary of operations for the Test Year. Schedule A-2 also presents projected results of operation for the year ending December 31, 2015 under the headings "present rates" and "proposed rates".

Q. Please describe the information contained on Schedule A-5.

A. Schedule A-5 presents a summary of changes in financial position for the Test-Year and the prior two calendar years. This schedule also includes the projected financial position as of December 31, 2015.

B. <u>"B" Schedules.</u>

Q. Please describe the information on Schedule B-1.

A. Schedule B-1 provides a summary of the company's OCRB and RCND rate base as of the end of the Test-Year, including the related pro forma adjustments to rate base. Rate base is comprised of net utility plant, certain regulatory assets and working capital, with deductions from rate base for accumulated deferred income taxes ("ADIT") customer advances for construction and customer deposits. The schedule also reflects the adjusted OCRB and RCND rate bases for the Total Company and what is jurisdictional to the Arizona Corporation Commission ("Commission").

Q. Please explain briefly the information contained on Schedule B-2, B-3 and B-4.

A. Schedule B-2 shows the pro forma adjustments to the OCRB. The information presented includes the actual per-book balances (as prepared under Generally Accepted Accounting Principles or "GAAP") and the end of the Test-Year, pro forma adjustments, and the adjusted balances on a Total Company and Commission jurisdictional basis. Schedule B-3 provides the same detail by functional account classification as shown on Schedule B-2, except that it is shown on an RCND basis. Schedule B-4 shows the plant in service accounts on a reconstructed cost new ("RCN") and RCND basis.

Q. Please explain briefly the terms RCN and RCND.

A. The ACC has defined RCND in Title 14 as:

> An amount consisting of the depreciated reconstruction cost new of the property (exclusive of contributions and/or advances in aid of construction) at the end of the Test-Year, used and useful, plus a proper allowance for working capital and including all applicable pro forma adjustments. Contributions and advances in aid of construction, if recorded in the accounts of the public service corporation, shall be increased to a reconstruction new basis. (A.A.C. R14-2-103(A) (3) (n)).

The RCN is the estimated cost of constructing the company's property in today's cost levels; this is done through a trending study. RCND refers to the net amount after deducting accumulated depreciation and amortization.

P. Please explain briefly the basis for the determination of the RCND rate base.

A. Plant in service and customer advances for construction reported at RCN are summarized from the results of a detailed plant cost trending study. The accumulated depreciation and ADIT reported on a RCN basis have been computed by multiplying the corresponding original cost balance by a ratio, the numerator of which is gross RCN of depreciable plant, and the denominator of which is gross original cost of depreciable plant. All other rate base elements are reflected at original cost.

Q. Please describe the plant cost trending study.

A. The trending study was prepared to establish an index number that represents a ratio between the cost of an item at its in-service date ("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 cost levels. For example, the RCN value for 2009 Vintage assets in Account no. 362, Distribution plant – Station Equipment was computed as follows:

2014 Index Value Acct 362 / 2009 Index Value
=2014 Cost Index for Acct 362

Original Cost of 2009 vintage assets in Acct. 362 X 2014 Cost index for Acct 362
=RCN for Acct 362 (current costs)

For most accounts, the Handy – Whitman Index of Public utility Construction Costs for the Plateau Region was employed (based on the most recently available index numbers). For plant accounts 303, 391, 393, 394 and 398 the "Marshall Valuation Service cost Index" was used. For plant accounts 392, 395, 396 and 397, the Bureau of Labor Statistics producer price index was used.

Once the RCN value has been established it is then multiplied by a net book value percentage. The net book value percent is simply the original cost less accumulated depreciation divided by the original cost.

For example, assume the Company has distribution station equipment with an original cost of $100,000, and accumulated depreciation of $50,000. The original cost less accumulated depreciation would be $50,000 ($100,000 - $50,000). Also, assume the

Vintage year is 2009 and has a RCN value of $117,500. Multiplying the RCN by the net book value percent yields RCND of $58,750 ($117,500 x 50%=$58,750).

Q. What is the Handy – Whitman Index?

A. It is an index of public utility construction costs that has been published continuously since 1924 by Whitman, Requardt and Associates of Baltimore, Maryland. The Handy – Whitman Index is a well-recognized, widely used and generally accepted method for measuring differences in property values for insurance and other purpose, including the valuation of public utility property for rate case purposes.

The Handy – Whitman Index is comprised of index values for various accounts prescribed by the FERC Uniform System of Accounts and for six geographical divisions of the country, including the Plateau Division, in which Arizona and New Mexico are located. These index numbers result from a comparison of the current prices of materials, labor, and equipment to prices in a base year. Index values are determined for each year as of January 1 and July 1.

The index values are used to determine cost trend factors, which are then applied to know original costs of similar plant and property to determine the fluctuation in cost between the date of installation and the date of valuation.

Q. What is the Marshall Index?

A. The Marshall Index, prepared by the firm of Marshall & Swift, is an index of construction cost trend valuations. It was used in the development of costs reported in the RCND Study for those plant accounts not reported by Handy – Whitman. The Company used the Bureau of Labor producer price index when neither the Handy – Whitman nor the Marshall indices were available.

Q. Please explain Schedule B-5.

A. This Schedule summarizes the computation of the allowance for working capital that the Company is requesting for inclusion in rate base in this rate case. I explain these computations latter in my testimony.

Q. Why are the original costs and RCND costs of working capital the same in Schedule B-5?

A. They are the same because the original costs are at current prices or have been adjusted to current prices, meaning they have not been significantly affected by inflationary factors.

C. <u>"C" Schedules.</u>

Q. Please explain Schedule C-1.

A. Schedule C-1 shows the Income Statement as prepared in accordance with GAAP for the twelve months ending December 31, 2014, the Test-Year in the case. It also summarizes the effect of proposed pro forma adjustments made to operating revenues and expenses, and the resulting adjusted net operating income.

Q. What is the purpose of Schedule C-2?

A. Schedule C-2 presents the detailed pro forma adjustments that reflect the full annual impact of operation changes, annualizations, normalizations, and other adjustments made to revenues and expenses. I will discuss these adjustments in detail later in my testimony (*see* section IV "Types of Pro Forma Adjustments").

Q. What is the purpose of Schedule C-3?

A. Schedule C-3 calculates the revenue conversion factor. This recognizes that the Company will need to "gross up" the net income deficiency to account for income taxes and additional bad debt.

D. <u>"E" Schedules.</u>

Q. Please Summarize Schedules E-1 through E-9.

A. The "E" Schedules were prepared in accordance with the filing requirements contained in Arizona Administrative Code ("AAC") R14-2-103. These schedules contain historical financial and accounting information, key operating statistics and notes that were extracted from the Company's regulatory books of accounts.

Q. Are UNS Electric's regulatory books of account still maintained in accordance with the FERC Uniform System of Accounts as required under A.A.C. R14-2-212.G.2.?

A. Yes they are.

Q. Please describe Schedule E-1.

A. Schedule E-1 contains the comparative UNS Electric balance sheets for the Test-Year and the two prior calendar years ending December 31, 2013, and December 31, 2012.

Q. Please describe Schedule E-2.

A. This schedule sets forth comparative income statements for the Test-Year and the two prior calendar years. The income statement for the Test-Year supports the actual test period income statement shown on Schedules C-1 and C-2.

Q. Please describe Schedule E-3.

A. This Schedule presents the comparative statements of cash flows for the Test-Year and the two prior calendar years

Q. Please describe Schedule E-4.

A. This Schedule reports the changes that occurred in stockholders' equity during the three-year period beginning January 1, 2012 and ending December 31, 2014. Changes occurring each year in both the number of shares outstanding and in the amounts of the various elements of stockholders' equity are reflected.

Q. Please describe Schedule E-5.

A. Page 1 of Schedule E-5 presents a summary of the balances in the various electric utility plant account categories and accumulated depreciation at December 31, 2014 and December 31, 2013, and the net changes therein, with plant in service presented on a functional basis. Pages 2 and 3 of Schedule E-5 present the same information on a more detailed basis, by individual electric plant account.

Q. Please describe Schedule E-6.

A. Schedule E-6 contains Operating Income Statements for the Test-Year and two previous calendar years. Retail revenues are reported by rate class. Operating Expenses are reported by major category.

Q. Please describe Schedule E-7.

A. This Schedule reports key electric operating statistics, in a comparative format, for the Test-Year and the two prior calendar years.

Q. Please describe Schedule E-8.

A. This Schedule shows the taxes charged to operating expenses by tax type for the Test-Year ended December 31, 2014, and the two prior calendar years ending December 31, 2013, and December 31, 2012.

Q. Please describe Schedule E-9.

A. This Schedule is intended to disclose important facts required for a proper understanding of the financial statements.

IV. PROFORMA ADJUSTMENTS.

Q. Please explain what a Pro Forma Adjustment is?

A. Public utility rates are based on the prudently incurred costs of providing safe, reliable service. The Company's revenue requirement is based on an historical Test-Year that reflects a level of operating revenues, expenses and net plant investment that occurred during that period. Because a historical Test-Year is being used, it creates a critical need to adjust the recorded Test-Year for actual occurrences not expected to recur or for events that are expected to occur but did not exist during the Test-Year. Such adjustments may be in the form of eliminations, annualizations or normalizations.

Q. What is an Elimination Adjustment?

A. Elimination adjustments are made to remove out-of-period or non-recurring transactions, or items that are not costs or revenues related to the provision of utility service; thus, not eligible for reflection in revenue requirements.

Q. What is an Annualization Adjustment?

A. Annualization adjustments are made to reflect the full, 12-month revenue or expense level of certain components of operating income. Annualization adjustments recognize that certain events that happen in a Test-Year are ongoing and must be spread over the entire Test-Year period. Examples are annualizations of revenues to reflect end-of-Test-Year customer levels and annualization of depreciation expense to reflect end-of-Test-Year plant investments and any proposed new deprecation rates. The Annualization adjustment synchronizes the Test-Years investments, revenue and cost relationships.

Q. What is a Normalization Adjustment?

A. 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. Moreover, some transactions eligible for reflection in revenue requirements are incurred at intervals less frequently than annually, provide benefits extending beyond a single year, or reoccur in significantly different amounts each year. As a result, the amounts recorded in the Test-Year may not be viewed as "normal," thus requiring a restatement for ratemaking purposes. Normalization adjustments are made in such instances when a Test-Year level of revenues or expenses is not representative of what would be expected on an on-going basis. Examples in this case include the adjustment for bad debt expense, the overtime factor implicit in the payroll adjustment, and the adjustment to normalize the level of outside legal expense.

V. RATE BASE PRO FORMA ADJUSTMENTS.

A. Acquisition Adjustment.

Q. Please explain the Acquisition Discount adjustment.

A. On August 11, 2003, UNS Energy acquired from Citizens Communications Company ("Citizens") its remaining electric utility assets located in Arizona. The Commission approved a Settlement Agreement regarding this acquisition ("Settlement Agreement") in Decision No. 66028 (July 3, 2003). The acquisition adjustment is necessary in order to properly reflect the discount, or negative acquisition premium, authorized by the Commission. Decision No. 66028 calls for the use of a $93.6 million "negative acquisition premium" (page 8, line 20) in the calculation of rate base for ratemaking purposes to reflect the lower purchase price.

Q. Is an acquisition adjustment normally recognized?

A. No, the Commission has generally not recognized acquisition adjustments. Under Commission rules, the original cost of utility property is the cost "at the time it is first devoted to public service." A.A.C. R14-2-102.A.6. In the case of an asset sale of a utility, the assets will have been devoted to service before the sale. Thus, the sale does not affect the original cost of the assets, either positively or negatively. In other words, the relevant cost is the "cost of [the] property to the person first devoting it to public service." A.A.C. R14-2-103.A.3.e. Thus, an acquisition adjustment is normally not appropriate. However, UNS Energy and the Commission did agree to the specific negative acquisition adjustment noted above. This pro forma adjustment is necessary so that the acquisition adjustment is limited for ratemaking purposes to the specific value agreed to by the Company and approved by the Commission.

Q. Why has UNS Electric historically recognized and acquisition adjustment to its rate base?

A. UNS Energy actually paid $104.3 million less than the original cost of the electric assets that it acquired from Citizens. This discount is larger than the negative acquisition premium required by the Commission as described above. Normally, an acquisition discount would not be considered for ratemaking purposes at all. However, in this case, the actual acquisition discount realized by the Company in acquiring the Citizens' assets is different than the negative acquisition premium approved by the Commission. This pro forma adjustment takes the discount and reduces it to the value of the discount authorized by the Commission. Overall, this adjustment results in a net increase to rate base.

Q. Please explain the accounting details further.

A. The "value" of the discount authorized by the Commission is equal to the $93.6 million figure stated in the Settlement Agreement, less amortization. The amortization has been calculated through December 31, 2014. Amortization reflects the fact that the assets which were purchased do not have an infinite life. Pursuant to the Settlement Agreement approved by the Commission, the amortization rate is the same as the depreciation rate for corresponding plant accounts. (Settlement Agreement at page 18.) According to Commission and the Federal Energy Regulatory Commission ("FERC") directives, the acquisition adjustment was a credit to accumulated depreciation. (Settlement Agreement at page 17.)

Q. Is the Acquisition Discount adjustment consistent with what the Commission approved in UNS Electric's last rate case, Docket No. E-04204A-12-0504?

A. Yes. The adjustment was prepared and calculated in the same manner as was approved by the Commission in the last UNS Electric rate case order, Decision No. 74235 ("2013 UNS Electric Rate Order").

B. Post-Test-Year Plant.

Q. Has the Commission allowed the use of Post Test-Year Plant before?

A. Yes. The Commission approved including Post-Test-Year Plant for UNS Electric in the 2013 UNS Electric Rate Order. The Commission has also allowed Post-Test-Year Plant in numerous other cases, including: Tucson Electric Power Company ("TEP") in Decision No. 73912 (June 27,2013); Arizona Public Service Company ("APS") in Decision No. 73183 (May 24, 2012), Rio Rico Utilities, Inc., in Decision No. 67279 (October 5, 2004); Arizona Water Co., in Decision No. 66849 (March 19, 2004); and Bella Vista Water Co., Inc., in Decision No. 65350 (November 1, 2002).

Q. Please explain the purpose of a Post-Test-Year Adjustment.

A. The purpose of a Post-Test-Year adjustment is to include in rate base, plant that will be used and useful prior to a new rate order. Under utility ratemaking theory, present customers should be required to pay costs directly incurred in providing their specific service.

Q. Is the Company requesting the allowance of a Post-Test-Year Adjustment in this proceeding?

A. In order to mitigate the overall rate increase proposed, UNS Electric is not requesting the inclusion of a Post-Test-Year adjustment in this filing, but reserves the right to do so in future filings.

C. Asset Retirement Obligation.

Q. Please explain the Asset Retirement Obligation ("ARO") Adjustment.

A. This adjustment is necessary to remove the balances of ARO assets reported in Plant in

Service. ARO assets exist only for those assets where there is a *legal* obligation to physically remove the assets at the end of their useful lives. In this rate case, the expected costs to remove the related assets from Plant in Service are implicit in the Negative Net Salvage component of our depreciation rates, and used in the preparation of the depreciation annualization adjustment.

D. Working Capital.

Q. What is Working Capital?

A. From a rate making perspective, working capital is the amount of investor funds required to finance the day to day operating expenditures of a regulated utility and is included as part of the rate base.

Q. What are the items of Working Capital for which the Company requests a return?

A. The Company requests that UNS Electric's rate base include the following components of Working Capital:

(i) Materials and Supplies;

(ii) Prepayments; and

(iii) Cash Working Capital.

The amounts requested for rate base inclusion for the materials and supplies and prepayments are based on Test-Year recorded balances, adjusted to reflect normal levels. The cash working capital component was determined by the use of the Lead-Lag Study Methodology, to be covered in-depth later herein.

Q. What is Cash Working Capital?

A. The receipt of customer revenues for the provision of service, and the disbursement of cash for the payment of the various costs of providing service rarely occur simultaneously. This is the fundamental consideration underlying the concept of Cash Working Capital. Cash Working Capital is generally viewed as the component of working capital that represents the amount of invested cash required to pay day-to-day operating expenses incurred in providing service to customers. It may either increase or decrease rate base. If the computation of Cash Working Capital produces a positive result, it is indicative that there is an additional investment for which a return is warranted, and thus, the amount is added to rate base. If the computation produces a negative result, there is an implicit non-investor funding of Cash Working Capital, requiring a rate base deduction.

Q. Please explain the Working Capital adjustment.

A. The Working Capital adjustment was computed in two pieces. First, as indicated on page 2 of Schedule B-5, the recorded end-of-Test-Year balances for Materials and Supplies, and Prepayments are adjusted to reflect the 13-month average monthly balances, in recognition of the variability in the monthly balances of the accounts. This is consistent with the treatment of such accounts in prior rate cases.

Second, Working Capital is adjusted for the inclusion in rate base of a measure of Cash Working Capital, developed through the preparation of a comprehensive lead-lag study.

Q. What is a lead-lag study?

A. A lead-lag study is a detailed analysis of the dynamic movement of funds throughout the organization, between the receivable and payable balance sheet accounts and related revenues and expenses that are reflected in the operating income component of revenue requirements. The method is generally viewed as the most accurate measure of Cash Working Capital. The Commission has stated a clear preference for the use of lead-lag studies in support of requested working capital amounts in rate cases.

The focal point of all lead-lag studies is the "point of service." That is the instant in time at which customers receive service and, coincident therewith, the utility incurs the cost of providing that service. A lead-lag study measures the average length of time between the provision of service and the ultimate receipt of payment from the customer ("revenue lag"). The result is compared with the average length of time between the point at which the utility incurs a cost of providing that service and the date upon which it makes the related cash disbursement ("payment lead" if payment precedes the cost benefit, or "payment lag" if the payment occurs after the cost benefit). Cash Working Capital reflects the effect on costs of service of the difference between the revenue lag and payment leads or lags.

As seen on page 3 of Schedule B-5, a lead-lag study computes the Cash Working Capital associated with each component of cost of service. The revenue lag is constant for all cost categories. The various major expenses are analyzed separately for purposes of developing a specific payment lead or lag. Once the applicable expense lead or lag is known, it is compared with the revenue lag to determine the net lead or lag for that study category. After dividing the net lead or lag by 365 days to arrive at an annual percentage factor, the result is multiplied by the corresponding adjusted Test-Year expense amount to quantify the Cash Working Capital requirement associated with that cost of service item. Consistent with past Commission policy, the effect of non-cash expenses such as depreciation and deferred income taxes are reflected in the study at a zero requirement.

Q. **How was the average revenue lag computed?**

A. The revenue lag is comprised of three distinct parts: the service lag; the billing lag; and the customer payment lag.

The service lag is measured from the midpoint of the period of service to the end of the period, the date upon which meters are read. A key underlying assumption is that service is taken uniformly throughout the period. With each customer being billed under twelve monthly billing cycles during the year, the average service lag is computed as 15.21 days [365 days / (12 X 2)].

The billing lag is typically measured from the meter read date to the date customer bills are prepared and balances entered into accounts receivable. The billing lag was computed based on actual meter read dates and bill mailing schedules used by UNS Electric during the Test-Year.

The customer payment lag is measured from the point at which the customer bill enters accounts receivable to the date that either a payment is received or the account is written off as uncollectible. That lag is determined by computing the average accounts receivable turnover for six months during the Test-Year. The accounts receivable turnover measures the average time during which a balance remains in accounts receivable and is computed by dividing the sum of the daily ending balances of accounts receivable by the sum of revenues billed and charged to accounts receivable during the study month.

Q. How were the payment leads and lags computed?

A. The payment leads and lags were developed based on analyses of actual payment history, contractual and statutory payment dates, and samples of expenditures.

Q. What was the overall result of the lead-lag study?

A. The study showed that there was negative cash working capital and a corresponding decrease was made as a pro forma adjustment to rate base.

E. Fortis Rate Base Adjustment.

Q. Please explain the Fortis Rate Base Adjustment.

A. On August 12, 2014, the Commission issued a final order that approved the merger with Fortis Inc. (Decision No. 74689). As part of the agreement, no merger related cost would be borne by the ratepayers. This adjustment removes all merger related cost allocated to UNS Electric and included in plant in service through overhead allocations. All costs associated with the merger were eliminated through pro forma adjustments to assure UNS Electric's cost of service was not impacted.

F. Gila River Adjustment.

Q. Please explain the Gila River Adjustment.

A. As part of UNS Electric purchase of the Gila River unit UNS Electric received transmission rights across the Arizona Public Service ("APS") transmission system. This adjustment reclassifies those costs to electric plant FERC account 303 (Miscellaneous intangible plant). This is consistent to Electric Plant Instruction Number 5 as explained by Company witness Jay Rademacher.

VI. OPERATING INCOME ADJUSTMENTS.

A. Non-Retail Revenue and Purchased Power.

Q. Please explain the Non-Retail Revenue and Purchased Power Adjustment.

A. This adjustment is necessary to eliminate 100% of the revenues associated with short-term wholesale sales which are credited to customers through the PPFAC. There are also costs associated with producing those revenues and those are expensed as incurred.

Without adjustment the profit on those sales would flow through the pro forma income statement. Therefore an adjustment is made to the Company's GAAP books to match the expenses with the revenues.

By making that adjustment, there is no operating income from wholesale transactions. That "profit" is maintained in the PPFAC reducing other costs which ultimately lowers the rolling PPFAC average rate.

B. <u>Purchased Power and Fuel.</u>

Q. Please explain the adjustment to Purchased Power and Fuel Expense.

A. This adjustment is an estimate of the Company's 2016 fuel, purchased power and purchased transmission expense to be recovered from customers when the rates approved in this proceeding are effective.

Therefore a cost estimate for the 2016 purchased power and fuel rate effective period was used. Company witness Michael Sheehan is sponsoring the projected cost per kWh used in our adjustment as the average base cost of fuel, purchased power and purchased transmission expense.

C. <u>Renewable Energy Standard & Tariff and Demand-Side Management.</u>

Q. Please explain the REST and DSM Adjustment.

A. This adjustment excludes from Test-Year revenue and expense activity directly related to the Renewable Energy Standard & Tariff ("REST") and Demand-Side management ("DSM") adjustor programs. These programs have separate funding mechanisms and should thus be excluded from Test-Year revenue and expenses.

D. Payroll Expense.

Q. Please explain the Payroll Expense Adjustment.

A. The Payroll Expense Adjustment is intended to reflect a normal level of salaries and wages in Test-Year operating expenses. The Payroll Expense Adjustment was computed based on an average of operations and maintenance ("O&M") wages for the 12 month periods ended December 31, 2013 and 2014, and reflects the known and measurable wage increase for 2015 and the estimated wage increase for 2016 - which will precede the anticipated date rates established in this proceeding will go into effect.

Q. Does the Payroll Expense Adjustment exclude capitalized payroll costs?

A. Yes. The adjustment only includes the amount directly recorded to O&M expenses and excludes the A&G labor cost allocated to capital projects.

E. Payroll Tax Expense.

Q. Please explain the Payroll Tax Expense Adjustment.

A. The Payroll Tax Expense Adjustment reflects the Company's taxes (Social Security and Medicare) that correspondingly increase as a result of the increased expense from the Payroll Expense Adjustment. The Company's effective employer's tax rate for 2015 was applied to the increased payroll expense reflected in the Payroll Expense Adjustment.

F. Pension and Benefits.

Q. Please explain the Pension and Benefits adjustment.

A. The Pension and Benefits adjustment is intended to include in operating expenses a level of pension and benefits expense reflecting the end-of-Test-Year work force, current pension and benefit actuarial expense level, and a normal level of business activity. The employee benefits covered by this adjustment include pensions, the Company's share of contributions to the employees' 401(k) plan, and current medical costs.

Q. Is the Pension and Benefits adjustment consistent with the 2013 UNS Electric Rate Order, Docket No. E-04204A-12-0504?

A. Yes. The adjustment was prepared and calculated in the same manner as was approved by the Commission in the last UNS Electric rate case.

G. Post-Retirement Medical.

Q. Please explain the Post-Retirement Medical adjustment.

A. The Post-Retirement Medical adjustment is intended to reflect in operating expenses a level of post-retirement medical payments reflecting the end-of-Test-Year work force level.

Q. Is the Post-Retirement Medical adjustment consistent with the 2013 UNS Electric Rate Order, Docket No. E-04204A-12-0504?

A. Yes. The adjustment was prepared and calculated in the same manner as was approved by the Commission in the 2013 UNS Electric Rate Order.

H. Rate Case Expense.

Q. Please explain the Rate Case Expense adjustment.

A. The Rate Case Expense adjustment addresses the outside costs already incurred, and expected to be incurred, in connection with this rate case. This amount is an estimate of the anticipated final cost and may be updated before this proceeding concludes. The adjustment amortizes the estimated expense over three years. This is the approximate time period between when UNS Electric filed this rate case and when the next rate case will likely occur.

I. Lost Fixed Cost Revenue.

Q. Please explain the Lost Fixed Cost Revenue Adjustment.

A. This adjustment removes all revenues collected under the Lost Fixed Cost Recovery mechanism ("LFCR"). These revenues are not collected as part of base rates, so they must be excluded from Test-Year revenues in order to calculate new base rates.

UNS Electric witness Craig Jones addresses the details in his Direct Testimony.

J. Bad Debt Expense.

Q. Please explain the Bad Debt Expense adjustment.

A. Bad Debt Expense is adjusted to a level reflective of final, pro forma weather-normalized, customer-annualized Test-Year operating revenues, and the average percentage of actual account write-offs experienced during the past three years. This method of calculating bad debt expense is consistent with past Commission accepted practice.

Q. Is the Bad Debt Expense adjustment consistent with the 2013 UNS Electric Rate Order, Docket No. E-04204A-12-0504?

A. Yes. The adjustment was prepared and calculated in the same manner as was approved by the Commission in the last UNS Electric Rate Order.

K. <u>Depreciation and Amortization Expense.</u>

Q. Please explain your proposed Depreciation and Amortization Expense Annualization Adjustment.

A. UNS Electric witness Dr. Ronald White preformed a 2014 Depreciation Study using data provided by the Company and verified by FERC Form 1. Using Dr. White's study, the Company updated the depreciation rates from the rates authorized in Decision No. 71914 (September 30, 2010).

Q. Why is this adjustment necessary?

A. The amount of depreciation expense recorded by UNS Electric during the Test-Year reflects less than a full year of depreciation for assets placed in service during the period and that are included in rate base. Moreover, it includes depreciation recorded on assets retired during the Test-Year, and thus, not included in rate base. This adjustment produces an annual depreciation expense consistent with the level of depreciable plant in rate base, and meets the definition of being known and measurable.

Q. How was the adjustment computed?

A. The adjustment was calculated by first computing the pro forma annualized depreciation expense and then deducting test year recorded depreciation expense. For generation assets pro forma annual depreciation was computed by multiplying the end-of-test-year plant balance in rate base at each generating location and related depreciable FERC plant account, by the respective current or proposed depreciation rate. For other accounts, annual depreciation was computed using the end-of-test-year balance in the respective accounts multiplied by the approved current depreciation or amortization rate. For certain assets, a portion of depreciation is capitalized as part of the cost of constructing new assets; thus, such amounts were excluded from the calculation.

Further, Decision No. 66028 requires the Company to account for the resulting acquisition discount as a subaccount of Account 108, Accumulated Depreciation, and that it be amortized as a reduction of depreciation expense using the same lives being used to depreciate the corresponding acquired assets. Annualizing the amortization of the acquisition discount is a part of, and was computed in the same manner as other elements of, the depreciation annualization adjustment.

L. <u>Short-Term Incentive Compensation.</u>

Q. Please Explain the Company's Short-Term Incentive Compensation program.

A. The Company's short-term Incentive Compensation is a cash –based program that effectively holds a portion of an employee's base salary "at risk". As such, a percentage of an employee's base salary is linked to the Company's annual financial and operational performance.

Even though the program creates "at-risk" compensation for employees, it contributes to the overall benefit package offered by UNS Electric. This allows the Company to remain competitive in attracting and retaining highly qualified employees, therefore reducing costs.

Q. How is the "at risk" portion of an employee's base salary determined?

A. The "at risk" portion is determined in accordance with the Company's Performance Enhancement Plan ("PEP"). Performance targets are established each year, typically before the end of the first's quarter. The objectives are tailored to drive behavior that supports the Company's strategy for delivering safe and reliable service to customers. Having an "at risk" component of compensation allows a company to focus its effort toward achieving measurable, meaningful goals and only rewarding employees when those goals are met. The 2014 PEP goals that benefited UNS Electric customers were as follows:

Category	Goals	Benefit to Retail Customers
Customer	• Excellent operations • Customer / Satisfaction • O&M cost containment	• The Company introduced a new Customer Satisfaction goal, measured by JD Power performance. Focus areas included call center responses time, customer communication improvements. • Goals that specifically target operations (system availability and reliability) and cost containment.
Employee	• Safe work environment	• Reducing injuries in the workplace reduces operation costs. • Continued focus on safety initiative components (leadership, employee involvement, and regulatory compliance).
Financial Strength	• Net income Target	• Enhances the ability of the Company to conduct business. A financially strong company is better able to secure credit from

		vendors and lenders. This allows UNS Electric to timely procure goods and services for operations, which promotes a higher quality of service to customers because the company is able to raise capital at a lower cost to build the infrastructure needed to serve the retail customers.

Using an incentive compensation program is less costly than increasing base salaries. This is because incentive compensation does not automatically drive increases in other employee costs that are included in "base compensation" such as: vacation pay; sick pay; long-term disability; 401 (K) employer matching contributions; and pension expense. As a result, the incentive compensation program is less costly than increasing base salaries.

Q. Which employees are eligible for the Short-Term Incentive Compensation program?

A. All non-union employees are eligible for the Short-Term Incentive Compensation program. Any form of compensation provided to the union work force must be collectively bargained. Currently, the union workforce is not comfortable with the "at risk" component of an incentive program or the ability to reward one employee more than another, as the incentive program is designed to do. Rather, the union has negotiated pay scales to increase base wages.

Q. Please explain the Short-Term Incentive Compensation Expense Adjustment.

A. The adjustment produces a pro forma Test-Year expense level reflecting 100% of the average PEP for the past three years (2012 – 2014). Since PEP payments are subject to payroll taxes, a portion of the adjustment reflects the incremental effect of payroll taxes.

Q. Is the Incentive Compensation adjustment consistent with the 2013 UNS Electric Rate order?

A. No. The Commission approved an adjustment that reflected only 50% of the average PEP for Company officers and senior management, and 100% of the average PEP for the remaining employees.

Q. Why is UNS Electric asking for 100% of Short-Term Incentive compensation in this case?

A. As I discussed earlier in my testimony, the PEP performance targets are based on factors that are critical to the long and short-term success of the Company. These targets put a portion of every employee's salary "at risk" which in effect, ties employee performance to the achievement of goals that directly benefit customers.

Q. Has the Commission allowed 100% recovery of Short-Term Incentive compensation before?

A. Yes, In Decision No. 69663, page 37, the Commission adopted Staff's position to allow recovery of 100% of APS Cash-Base Incentive Compensation Program expense because the "at risk" pay program ties employee performance to the customer's benefit:

> APS' variable incentive program is an "at risk" pay program where a part of an employee's annual cash compensation is put at risk and expectations are established for the employee at the start of the year. If certain performance results are achieved, a predictable award will be earned based upon objective criteria. The actual amount of the award depends upon the achieved results. The intent of the plan is to: link pay with business

performance and personal contributions to results; motivate participants to achieve higher levels of performance; communicate and focus on critical success measures; reinforce desired business behaviors, as well as results; and to reinforce an employee ownership culture. (APS Exhibit No. 51, Gordon Rebuttal, p. 8) Staff did not oppose inclusion of the TY variable incentive expense in cost of service, noting that although corporate earnings serve as a threshold or precondition to the payout, the TY level of expense is tied primarily to performance measures that directly benefit APS customers. (Staff Exhibit No. 43, Dittmer Direct, p. 110).

Q. Does the cash-based Short-Term Incentive Compensation program result in salaries and wages that exceed the market?

A. No. The total cash compensation approximates the median of the market, based on the most recent benchmark studies. The benchmarking information demonstrates that the amounts are reasonable.

M. Injuries and Damages.

Q. Please explain the Injuries and Damages Expense Adjustment.

A. The Injuries and Damages Expense adjustment normalizes the Test-Year expense to reflect the average annual expense for the 12 month periods ending December 2012, 2013 and 2014.

N. Membership Dues.

Q. Please explain the Membership Dues Expense adjustment.

A. This adjustment removes the portion of membership dues paid to Edison Electric Institute for legislative advocacy, and other dues paid to organizations that have been voluntarily excluded from pro forma operating expenses for purposes of this rate case.

O. Fortis Acquisition Costs.

Q. Please explain the Fortis Acquisition Costs Adjustment.

A. This adjustment removes all merger related cost from the income statement.

Q. Does this conclude your Direct Testimony?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE – INTERIM CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
VACANT

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

EXHIBIT
UNSE-12
ADMITTED

Rebuttal Testimony of

David J. Lewis

on Behalf of

UNS Electric, Inc.

January 19, 2016

Table of Contents

Exhibits

I. INTRODUCTION.

Q. Please state your name and business address.

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

Q. Did you file Direct Testimony in this proceeding?

A. Yes.

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

A. My Rebuttal Testimony is filed on behalf of UNS Electric, Inc. ("UNS Electric" or "Company").

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

A. I address certain adjustments that Staff witness Donna Mullinax recommends in her Direct Testimony. I also address adjustments that Residential Utility Consumer Office ("RUCO") witness Jeffrey Michlik proposes in his Direct Testimony. While the Company will agree to most of Staff's adjustments for purposes of this rate case only, I am addressing only those adjustments where the Company is not in agreement. Any inadvertent omission of discussion of any adjustment should not be considered an acceptance of the position or recommendation.

II. COMPUTATION CORRECTIONS TO STAFF'S AND RUCO'S DIRECT FILINGS.

Q. Are there computation errors that you have identified within Staff's or RUCO's adjustments?

A. Yes, I have provided an attachment, **Exhibit DJL-R-1**, which summarizes and explains the computation corrections that I have identified and sets forth the appropriate computation.

Q. What computation errors did you identify?

A. As explained in **Exhibit DJL-R-1**, the following errors were identified.

1. Correction of Staff's adjustment E-3 Injuries and Damages. Staff inadvertently did not apply the ACC Jurisdictional factor in its calculation.
2. Correction of Staff's adjustment E-4 Payroll Expense & Taxes. This correction is needed to correct for the double exclusion of incentive compensation. Staff's adjustment was prepared based on information provided in data response STF 6.12. The question asked to "explain the Incentive Compensation shown on the Payroll Expense work papers." UNS Electric's response addressed the question by stating "the Incentive Comp as shown 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 on page 354." UNS Electric's response intended to identify how the incentive compensation was reconciled to FERC Form 1. It was not our intent to suggest that the Payroll Expense adjustment included incentive compensation dollars.
3. Correction of Staff's adjustment E-5 Incentive Compensation. Staff inadvertently did not apply the ACC Jurisdictional factor in the calculation.
4. Correction of Staff's Schedule D – Capital Structure. On Schedule D, the Fair Value Rate of Return ("FVROR") calculation was linking to UNS Electric's original filed

position and not to Staff's recommended position. Once corrected the FVROR should be 5.63%.

5. Correction of RUCO's Base cost of fuel Schedule JMM-13. RUCO adjusted the Company's updated base cost of fuel to revert the base cost of fuel back to the base cost of fuel authorized in the Company's last rate case. Using the updated base cost of fuel is standard practice in electric rate cases, and this approach was used in the Company's last rate case. Fuel costs are recovered on a dollar-for-dollar basis (no profit) through the purchased power and fuel adjustment mechanism. In a rate case, it is appropriate to update the base cost of fuel to provide a new base for the adjustment mechanism. If the revised revenue from base cost of fuel is not updated in this way, then the difference must be reflected in the revenue requirement through a corresponding adjustment to expenses. RUCO agrees that a correction is needed. In response to the Company's data request UNSE 2.14, RUCO states: "... RUCO agrees if Test Year Revenues are adjusted to reflect an updated Base Cost of Power, then expenses should reflect the adjusted level of power expense; as fuel revenues must equal fuel expense, RUCO will revise operating income adjustment no. 1, in its Surrebuttal testimony."

Q. Did you contact Staff or RUCO to address the computation corrections?

A. Yes. I contacted Staff witness Donna Mullinax. UNS Electric witness Craig Jones spoke to RUCO witness Jeffrey M. Michlik.

Q. Did Donna Mullinax agree with the Company's recommended corrections?

A. Yes, Donna Mullinax accepted our recommended corrections and it is the Company's understanding that she will be revising Staff's base rate increase to $18.5M in her surrebuttal testimony.

III. REBUTTAL TO OPERATING INCOME ADJUSTMENTS.

A. Short Term Incentive Compensation.

Q. Did Staff or RUCO reduce the pro forma Short-Term Incentive Compensation cost contained within the Company's requested revenue requirements?

A. Yes, Both Staff and RUCO witnesses recommended that the pro forma level of Short-Term Incentive Compensation expense be reduced. Although Staff and RUCO adjustments differ slightly in their calculations, they both support the conclusion that the Company's compensation program should be borne equally by the shareholders and ratepayers.

The Company strongly disagrees with the "who benefits" analysis as a tool for what percentage of recovery to be afforded to the Company. The decision to allow recovery should be based on whether the total compensation, including incentive pay, is fair and reasonable. If so, it is part of the cost of service and should be allowed. Neither Staff nor RUCO contend that the overall compensation, including incentive pay, is unreasonable or imprudent. Accordingly, it should be fully recoverable. To allow only partial recovery based on a "who benefits" approach is inappropriate. Almost any expense could be seen to "benefit" both ratepayers and shareholders. The Commission should allow the Company to recover its cost of service, which does not occur under Staff and RUCO's proposals to allow recovery of only a percentage of reasonable expenses.

Q. Are the arguments for full recovery of Short-term incentive compensation in your direct testimony similar to arguments in UNS Electric's previous rate case?

A. Yes, the arguments are essentially unchanged. The Company recognizes that recent Commission decisions rejected recovery of 100% of Short-Term incentive compensation.

However, the Commission recently allowed EPCOR Water Arizona, Inc. ("EPCOR") (Decision No. 75268) to recover in rates incentive compensation so long as the total compensation, including incentive pay was reasonable. The Company believes the costs associated with the short- term incentive program is reasonable, fair and prudent.

B. Rate Case Expense.

Q. Did Staff or RUCO dispute the Company's pro forma rate case expense?

A. Staff did not object to the Company's Rate Case Adjustment in their Direct Testimony. RUCO recommend the inclusion of $350,000 normalized over 3 years as opposed to $400,000 normalized over 3 years. See RUCO Schedule JMM-18.

Q. Do you agree with RUCO's recommendation of a normalized annual allowance of $116,667?

A. No. As of January 1, 2016 UNS Electric has already incurred costs well in excess of the $400,000 requested in its Application through the use of substantial TEP employee time (which is allocated to UNS Electric) and outside consulting services and is expected to increase. These costs are the incremental real cost associated with filing this case and should be fully recoverable. Moreover, there are additional factors present in this rate case that are outside of the control of the Company that has generated additional rate case expense. For example, there are 19 Intervenors in this rate case and the Company has responded to over 1,700 data requests, and there are approximately 40 witnesses that have pre-filed testimony which will result in a lengthy and costly hearing. Although the Company could easily update its rate case expense request to include these additional costs, it has elected to not do so.

Q. What is the reason for RUCO's recommendation to allow recovery of $350,000 of rate case expense?

A. RUCO seems to have predicated their recommendation based on the $300,000 authorized amounts from the prior three rate cases with an additional $50,000 due to the complexities in this case. This grossly understates the additional complexities and costs that I just discussed.

To base a recommendation purely on what was approved in UNS Electric's 2008 rate case and ignore the additional expenses that the Company has no choice but to incur, is simply unfair to the Company and is inherently unreasonable under the circumstances.

IV. CONCLUSION.

Q. What is the Company's recommendation for revenue requirement?

A. While UNS Electric strongly believes that the requested increase in non-fuel base rates of $22.6 million represents the true "Cost of Service" of providing dependable and reliable service to their customers, for purposes of this rate case, UNS Electric accepts Staffs revised non-fuel base rate increase of $18.5M.

Q. Does this conclude your Testimony?

A. Yes, it does.

Exhibit DJL-R-1

UNS Electric, Inc.
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
Test Year Ended December 31, 2014

	As Filed UNSE 12/31/14	STAFF Revised Pos.	RUCO Revised Pos.	UNSE Revised Pos.	STAFF Summary of Position	RUCO Summary of Position
Original Cost Rate Base - Unadjusted	$272,560,320	$ 272,560,320	$272,560,320	$ 272,560,320		
Rate Base Adjustments						
Acquisition Discount Adjustment	4,371,344	4,371,344	4,371,344	$ 4,371,344	No Adjustment	No Adjustment
Accumulated Deferred ITC	4,272,926	4,272,926	4,272,926	$ 4,272,926	No Adjustment	No Adjustment
Accumulated Deferred Income Taxes	(1,773,667)	(1,773,667)	(9,240,729)	$ (1,773,667)	No Adjustment	to reduce rate base for the NOL associated bonus depreciation.
Fortis Rate Base Adjustment	(10,249)	(10,249)	(10,249)	$ (10,249)	No Adjustment	No Adjustment
Gila River Adjustment	(11,389)	(2,011,389)	(11,389)	$ (2,011,389)	To Reduce RB by $2M related to depreciation expense as deferred by the accounting order for Gila River.	
ARO	(1,101,971)	(1,101,971)	(1,101,971)	$ (1,101,971)	No Adjustment	
Working Capital	(6,294,187)	(6,123,207)	(6,288,758)	$ (6,123,207)	CWC adjustment- Increase $187,758. D&O prepaid reduction by 50% ($16,778). Staff adjustment for D&O insurance is at Total Company not ACC jurisdiction. Staff also used 50% reduction based on total expense not average balance.	CWC and D&O prepaid
Total Adjustments to Rate Base	(547,193)	(2,376,213)	(8,008,826)	(2,376,213)		
Rate Base	$ 272,013,127	$ 270,183,980	$ 264,551,496	$ 270,183,980		
Requested Rate of Return	7.67%	7.22%	6.61%	7.22%	Capital Structure: 47.17 % debt @ 4.66% , 52.83% Equity @ 9.5%. FVI .50%. ROR on OCRB 7.22%	Capital Structure: 47.17 % debt @ 4.66% , 52.83% Equity @ 8.35%. FVI .82%. ROR on OCRB 6.61%
Required Operating Income OCRB	$20,852,600	$19,500,907	$17,486,854	$19,500,907		
Fair Value Increment of Rate Base	$83,704,602	$83,707,020	$80,579,090	$83,707,020		
Fair Value Rate Base (FVRB)	$355,717,730	$353,891,000	$345,130,586	$ 353,891,000		
Proposed FVROR	1.50%	0.50%	0.82%	0.50%	**Modified from original Position:** To correct formula error FVROR changed from 5.60% to 5.63%	Reflects OCRB proposed changes
Required Operating Income on FVRB	1,255,569	$418,548	$660,139	$418,548		
Original Operating Income - Unadjusted	$22,042,438	$22,042,438	$22,042,438	$22,042,438		
Operating Revenue Adjustments						
LFCR	(1,377,647)	(1,377,647)	(1,377,647)	(1,377,647)	No Adjustment	
Non-Retail Rev, Fuel & Purchase Power	-	7,781,533	3,090,705	7,781,533	Staff recommended a Base Cost of fuel of $0.053288 vs $0.048427 requested by UNSE. Staff's rate consists of actual costs from January through August 2015 and forecasted costs for September through December 2015.	RUCO adjusted base fuel revenue to reflect $0.056603 average rate. No corresponding expense adjustment.
Customer and Weather Adjustment	(6,021,912)	(6,021,912)	(6,021,912)	($6,021,912)	No Adjustment for Weather. Staff requests that the company monitor revenues and file quarterly. Concerns are surrounding the larger customers entering back into the market.	N/A
REST & DSM	(1,537,369)	(1,537,369)	(1,537,369)	($1,537,369)	No Adjustment	
Service Fees	95,034	95,034	95,034	$95,034	No Adjustment	
Other Revenues	(45,506)	(45,506)	(45,506)	($45,506)	No Adjustment	
Total Adjustments to Operating Revenues	(8,887,400)	($1,105,867)	($5,796,695)	($1,105,867)		

UNS Electric, Inc.
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
Test Year Ended December 31, 2014

	As Filed UNSE 12/31/14	STAFF Revised Pos.	RUCO Revised Pos.	UNSE Revised Pos.	STAFF Summary of Position	RUCO Summary of Position
Operating Expense Adjustments						
Payroll Expense	(172,011)	(172,011)	(172,011)	(172,011)	Staff removed the Incentive Comp amounts associated with payroll. The adjustment however does not include Incentive comp. Staff use Total Incentive Comp and did not exclude the portion that goes to Capital. After **conversation with Staff witness the adjustment will be Withdrawn.**	No Adjustment
Payroll Tax Expense	(13,397)	(13,397)	(13,397)	(13,397)	Staff removed the Incentive Comp amounts associated with payroll. The adjustment however does not include Incentive comp. Staff used Total Incentive Comp and did not exclude the portion that goes to Capital. After **conversation with Staff witness the adjustment will be Withdrawn.**	No Adjustment
Pension & Benefits	(123,376)	(123,376)	182,472	(123,376)	No Adjustment	RUCO used a 3 year average for Medical and Dental - did not account for the amount that is O&M only.
Retiree Medical	(37,384)	(37,384)	(37,384)	(37,384)	No Adjustment	No Adjustment
Rate Case Expense	(53,349)	(53,349)	(36,682)	(53,349)	No Adjustment	Allowed $350K over 3yrs
Bad Debt Expense	358,151	489,791	358,151	489,791	Staff excluded Mercator write off from their normalization ($450K). Staff used a Three Year retail revenues total divided by 3 year retail expense.	No Adjustment
Depr. & Amort. Expense	6,624,227	6,624,227	6,624,227	6,624,227	No Adjustment	No Adjustment
Property Tax	(873,950)	(873,950)	(873,950)	(873,950)	No Adjustment	No Adjustment
Incentive Compensation	(169,378)	(14,023)	46,873	(14,023)	Staff adjusts for a 2yr average. And 50-50 sharing between ratepayers and Stakeholders.	To reduce Operating income for Wellness programs and Spot awards. And to reflect 50/50 sharing of PEP
Injuries and Damages	(355,542)	(35,442)	(11,727)	(35,442)	To remove the $1M insurance deductible we booked in 2013 but reversed in July 2015 due to a favorable outcome.	Ruco removed all of the $1,071,000 then applied a 3yr average
Membership Dues	10,590	10,590	26,107	10,590	No Adjustment	Ruco excluded all of UARG and 29.55% of EEI; leaving only their estimate of legislative advocacy
Gila River Deferred Cost	(3,100,000)	(3,100,000)	(3,100,000)	(3,100,000)	No Adjustment	No Adjustment
Fortis Acquisition Costs	5,522,093	5,522,093	5,522,093	5,522,093	No Adjustment	No Adjustment
Gila O&M and Outages	(3,370,536)	(3,370,536)	(3,370,536)	(3,370,536)	No Adjustment	No Adjustment
Income Taxes	5,174,155	4,915,650	4,751,190	4,915,650	To adjust for STAFF changes (bad debt, Inj&dam,Payroll,Incentive Comp, D&O, Interest Sync, Purchased Power)	Ruco Interest Sync
OATT	(14,531,456)	(14,511,531)	(14,531,456)	(14,511,531)	Staff is recommending the OATT Revenue Requirement amount that is currently used for the TCA rate in effect during the test year (2013 Plant data) should be used.	No Adjustment
D&O Insurance	-	20,028	70,077	20,028	Removal of 50% of the D&O related expense.	To reflect a 50-50 sharing
Purchased Power	-	(7,781,533)	(3,090,705)	(7,781,533)	Corresponding adjustment to revenue.	Corresponding adjustment to revenue.
Total Adjustments to Operating Expense	(5,111,163)	(12,504,153)	(7,656,658)	(12,504,153)		
Total Net Adjustments	(13,998,563)	(13,610,020)	(13,453,353)	(13,610,020)		
Adjusted Operating Income	$8,043,875	$8,434,000	$8,589,085	$8,434,000		
Operating Income Deficiency	$14,064,294	$11,485,455	$9,557,907	$11,485,455		
Gross Revenue Conversion Factor	1.6084	1.6070	1.6084	1.6070		
Increase in Gross Revenue Requirement	$22,621,010	$18,457,000	$15,372,938	$18,457,000	This is due to the removal of $450,000 bad debt expense reserve for mining company bankruptcy filing.	No Adjustment

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

Rejoinder Testimony of

David J. Lewis

on Behalf of

UNS Electric, Inc.

February 29, 2016

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Exhibit

I. INTRODUCTION.

Q. Please state your name and business address.

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

Q. Did you file Direct or Rebuttal Testimony in this proceeding?

A. Yes.

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

A. My Rejoinder Testimony addresses the testimonies of Robert B Mease and Jeffery Michlik filed on behalf of the Residential Utility Consumer Office ("RUCO"). Specifically, I discuss the non-fuel revenue requirement presented by Mr. Michlik and the revenue increase of $15.1 million that Mr. Mease references in his Surrebuttal Testimony.

II. RESPONSE TO SURREBUTTAL REVENUE REQUIREMENT ADJUSTMENT.

Q. Did RUCO accept the revenue requirement adjustments you described in your Rebuttal Testimony?

A. Yes, RUCO accepted all of the revised adjustments except the proposed base cost of fuel.

Q. Do you agree with RUCO's base cost of fuel amount?

A. No. In calculating the base cost of fuel amount, RUCO applied $0.053689 per kWh to retail sales of 1,626,067,036 kWh. Although I agree that $0.053689 represents the actual cost per kWh that the Company incurred from January through December 2015, I do not agree with the sales volumes used. RUCO should have used the adjusted sales volumes filed in this case of 1,600,809,167 kWh. Had the correct retail sales volumes been used the base cost of fuel would have been $85,945,843.

Q. Are there any other adjustments in RUCO's rebuttal position you would like to address?

A. Yes, RUCO decreased test year medical expense by $316,694, and increased dental expenses by $10,846. Upon further review, RUCO's adjustments did not take into account the portion that should have been allocated to capital investments. Had the adjustment been calculated to reflect the portion that would have been allocated to capital, medical expense would have decreased by $187,737, and dental expense increased by $6,430.

Q. Does the Company agree with RUCO's revised Revenue Requirement presented by Mr. Michlik?

A. No. Mr. Michlik Surrebuttal Testimony is recommending a gross revenue requirement of $17,206. This is largely due to the Rate of Return on common equity of 9.13%. However, in Mr. Mease's Surrebuttal Testimony, page 21 lines 4-6, Mr. Mease states that RUCO would consider recommending Staff's cost of common equity of 9.50% provided "the overall revenue requirement" is not greater than $15.1 million.

Q. Do you believe Mr. Mease meant to refer to the "overall revenue *requirement*", or was he instead referring to the "overall revenue *increase*"?

A. I believe he meant to refer to the overall revenue increase. That is because the overall revenue requirement is much higher, and Mr. Mease refers to a "$7.5 million overall reduction in total revenue increase" on page 22 of his Surrebuttal Testimony. The referenced amount of $15.1 million is indeed $7.5 million lower than the non-fuel revenue increase of $22.6 million requested by UNS Electric in its rate application.

Q. **Is the Company willing to accept a non-fuel revenue increase of $15.1 million?**

A. As discussed in the Rejoinder Testimony of Company witness Kentton Grant, the Company would be willing to accept a $15.1 million non-fuel revenue increase, and the related treatment of deferred Gila River Unit 3 costs, as long as the Company is provided with a reasonable opportunity to actually earn a 9.50% return on equity. However, this does not mean that UNS Electric agrees with the rationale underlying RUCO's additional operating expense adjustments and reserves the right to oppose them in future rate cases.

Q. **Do you have any other comments?**

A. Yes. As part of my Rejoinder Testimony I am submitting revised **Exhibit DJL-RJ-1** that explains in more detail the Surrebuttal positions of Staff and RUCO and the revised revenue requirement deficiency for RUCO with the above corrections to their filed testimony.

Q. **Does this conclude your Testimony?**

A. Yes, it does.

Exhibit DJL-RJ-1

UNS Electric, Inc.
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
Test Year Ended December 31, 2014

	As Filed UNSE 12/31/14	STAFF Rebuttal Pos.	RUCO Rebuttal Pos.	UNSE Rejoinder Pos.	STAFF Summary of Position	RUCO Summary of Position
Original Cost Rate Base - Unadjusted	$272,560,320	$ 272,560,320	$272,560,320	$272,560,320		
Rate Base Adjustments						
Acquisition Discount Adjustment	4,371,344	4,371,344	4,371,344	$4,371,344	No Adjustment	No Adjustment
Accumulated Deferred ITC	4,272,926	4,272,926	4,272,926	$4,272,926	No Adjustment	No Adjustment
Accumulated Deferred Income Taxes	(1,773,667)	(1,773,667)	(1,773,667)	($1,773,667)	No Adjustment	No Adjustment
Fortis Rate Base Adjustment	(10,249)	(10,249)	(10,249)	($10,249)	No Adjustment	No Adjustment
Gila River Adjustment	(11,389)	(2,011,389)	(2,011,389)	($2,011,389)	To Reduce RB by $2M related to depreciation expense as deferred by the accounting order for Gila River.	Accepted Staff's Adjustment
ARO	(1,101,971)	(1,101,971)	(1,101,971)	($1,101,971)	No Adjustment	No Adjustment
Working Capital	(6,294,187)	(6,014,606)	(6,014,542)	($6,014,542)	CWC adjustment- Increase $279,581. D&O prepaid reduction by 50% ($16,778). Staff also used 50% reduction based on total expense not average balance.	Accepted Staff's Adjustment
Total Adjustments to Rate Base	(547,193)	(2,267,612)	(2,267,548)	(2,267,548)		
Rate Base	$ 272,013,127	$ 270,292,716	$ 270,292,780	$ 270,292,780		
Requested Rate of Return	7.67%	7.22%	7.22%	7.22%	Capital Structure: 47.17 % debt @ 4.66% , 52.83% Equity @ 9.5%. FVI .50%. ROR on OCRB 7.22%	Accepted Staff's Adjustment
Required Operating Income OCRB	$20,852,600	$19,508,890	$19,508,892	$19,508,892		
Fair Value Increment of Rate Base	$83,704,602	$83,706,670	$83,706,669	$83,706,669		
Fair Value Rate Base (FVRB)	$355,717,730	$353,999,386	$353,999,449	$353,999,449	Modified from original Position: To correct formula error FVROR changed from 5.60% to 5.63%	Accepted Staff's Adjustment
Proposed FVROR	1.50%	0.50%	0.50%	0.50%		
Required Operating Income on FVRB	1,255,569	$418,533	$418,533	$418,533		
Original Operating Income - Unadjusted	$22,042,438	$22,042,438	$22,042,438	$22,042,438		
Operating Revenue Adjustments						
LFCR	(1,377,647)	(1,377,647)	(1,377,647)	(1,377,647)	No Adjustment	No Adjustment
Non-Retail Rev. Fuel & Purchase Power	-	7,781,534	9,779,021	9,779,021	Staff recommended a Base Cost of fuel of $0.053288 vs $0.048427 requested by UNSE. Staff's rate consists of actual costs from January through August 2015 and forecasted costs for September through December 2015. This rate is subject to change prior to new base cost of fuel rates going into effect.	RUCO recommends a Base Cost of Fuel rate of $0.053689 per kWh. This is based on 2015 actual fuel and purchase power costs and equates to $87.3M using retail sales of 1,626,067,036 kWh.
Customer and Weather Adjustment	(6,021,912)	(6,021,912)	(6,021,912)	(6,021,912)	No Adjustment for Weather. Staff requests that the company monitor revenues and file quarterly. Concerns are surrounding the larger customers entering back into the market.	No Adjustment
REST & DSM	(1,537,369)	(1,537,369)	(1,537,369)	(1,537,369)	No Adjustment	No Adjustment
Service Fees	95,034	95,034	95,034	95,034	No Adjustment	No Adjustment
Other Revenues	(45,506)	(45,506)	(45,506)	(45,506)	No Adjustment	No Adjustment
Total Adjustments to Operating Revenues	(8,887,400)	($1,105,866)	$891,621	$891,621		

UNS Electric, Inc.
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
Test Year Ended December 31, 2014

	As Filed UNSE 12/31/14	STAFF Rebuttal Pos.	RUCO Rebuttal Pos.	UNSE Rejoinder Pos.	STAFF Summary of Position	RUCO Summary of Position
Operating Expense Adjustments						
Payroll Expense	(172,011)	(172,011)	(172,011)	(172,011)	Staff adjustment was Withdrawn.	No Adjustment
Payroll Tax Expense	(13,397)	(13,397)	(13,397)	(13,397)	Staff adjustment was Withdrawn.	No Adjustment
Pension & Benefits	(123,376)	(123,376)	57,932	57,932	No Adjustment	RUCO used a 3 year average for Medical and Dental - did not account for the amount that is O&M only.
Retiree Medical	(37,384)	(37,384)	(37,384)	(37,384)	No Adjustment	No Adjustment
Rate Case Expense	(53,349)	(53,349)	(37,344)	(37,344)	No Adjustment	Allowed $350K over 3yrs
Bad Debt Expense	358,151	489,791	489,791	489,791	Staff excluded Mercator write off from their normalization ($450K). Staff used a Three Year retail revenues total divided by 3 year retail expense.	Accepted Staff's Adjustment
Depr. & Amort. Expense	6,624,227	6,624,227	6,624,227	6,624,227	No Adjustment	No Adjustment
Property Tax	(873,950)	(873,950)	(873,950)	(873,950)	No Adjustment	No Adjustment
Incentive Compensation	(169,378)	(14,023)	32,529	32,529	Staff adjusts for a 2yr average. And 50-50 sharing between ratepayers and Stakeholders.	Accepted Staff's adjustments. Plus a reduction to Operating income for Wellness programs and Spot awards.
Injuries and Damages	(355,542)	(35,442)	(35,442)	(35,442)	To remove the $1M insurance deductible we booked in 2013 but reversed in July 2015 due to a favorable outcome.	Accepted Staff's Adjustment
Membership Dues	10,590	10,590	26,106	26,106	No Adjustment	Ruco excluded all of UARG and 29.55% of EEI; leaving only their estimate of legislative advocacy
Gila River Deferred Cost	(3,100,000)	-	-	-	No Adjustment	No Adjustment
Fortis Acquisition Costs	5,522,093	5,522,093	5,522,093	5,522,093	No Adjustment	No Adjustment
Gila O&M and Outages	(3,370,536)	(3,370,536)	(3,370,536)	(3,370,536)	No Adjustment	No Adjustment
Income Taxes	5,174,155	3,750,327	3,652,767	3,652,767	To adjust for STAFF changes (bad debt, Inj&dam,Payroll,Incentive Comp, D&O, Interest Sync, Purchased Power)	Ruco interest Sync
OATT	(14,531,456)	(14,511,531)	(14,511,531)	(14,511,531)	Staff is recommending the OATT Revenue Requirement amount that is currently used for the TCA rate in effect during the test year (2013 Plant data) should be used.	No Adjustment
D&O Insurance	-	20,028	20,028	20,028	Removal of 50% of the D&O related expense.	Accepted Staff's Adjustment
Purchased Power	-	(7,781,534)	(9,779,021)	(9,779,021)	Corresponding adjustment to revenue.	Corresponding adjustment to revenue.
Total Adjustments to Operating Expense	(5,111,163)	(10,569,477)	(12,405,143)	(12,405,143)		
Total Net Adjustments	(13,998,563)	(11,675,343)	(11,513,522)	(11,513,522)		
Adjusted Operating Income	$8,043,875	$10,369,097	$10,530,917	$10,530,917		
Operating Income Deficiency	$14,064,294	$9,558,327	$9,396,509	$9,396,509		
Gross Revenue Conversion Factor	1.6084	1.6070	1.6070	1.6070	This is due to the removal of $450,000 bad debt expense reserve for mining company bankruptcy filing.	Accepted Staff's Adjustment
Increase in Gross Revenue Requirement	$22,621,010	$15,360,039	$15,099,716	$15,099,716		

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 FOR RELATED APPROVALS.

DOCKET NO. E-04204A-15-______

UNSE-14
ADMITTED

Direct Testimony of

Jason J. Rademacher

on Behalf of

UNS Electric, Inc.

May 5, 2015

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I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Jason J. Rademacher and my business address is 88 East Broadway, Tucson, Arizona, 85701.

Q. By whom are you employed and what are your duties and responsibilities?

A. I am employed by Tucson Electric Power Company ("TEP"), a wholly-owned subsidiary of UNS Energy Corporation ("UNS Energy"), as Director of Plant Accounting and Tax Services. In my position I am responsible for all tax and fixed asset accounting and compliance filings related to income, sales & use and property tax for all the regulated subsidiaries of UNS Energy, including TEP, UNS Electric, Inc. ("UNS Electric" or the "Company") and UNS Gas, Inc. ("UNS Gas").

Q. Would you please describe your education, background and experience?

A. I received a Bachelor of Science Degree in Accounting from the University of Buffalo in 1999 and I am a Certified Public Accountant licensed to practice in the State of Arizona. Since joining TEP in 2003, I have held various positions within the accounting organization with increasing leadership responsibility. I have been in my current role since 2014.

Q. What is the purpose of your testimony in this proceeding?

A. My direct testimony supports UNS Electric's rate request in this proceeding. I am the sponsoring witness for several pro forma adjustments as well as UNS Electric's request for a property tax deferral.

Q. Please summarize your testimony.

A. In my testimony, I provide support for the following rate-base items:

- Accumulated Deferred Income Tax ("ADIT") adjustment; and
- Accumulated Deferred Investment Tax Credit ("ITC").

In addition, I am the sponsoring witness for the following income statement pro forma accounting adjustments:

- Property Tax Expense; and
- Income Tax Expense.

Finally, I explain UNS Electric's request for a Property Tax Deferral and the Company's acquisition accounting for its 25% interest in Gila River Power Station Unit 3 ("Gila River").

II. PRO FORMA ADJUSTMENTS.

Q. Please explain the consideration of pro forma adjustments in the rate case process.

A. Public utility rates are based on the prudently-incurred costs of providing safe, reliable service. The revenue requirement underlying rates is developed on the basis of a test year that reflects a level of operating revenues and expenses and net plant investment that represents normal conditions that may be expected to exist during the time that resulting rates may be in effect. This affords the utility a reasonable opportunity to achieve a fair rate of return, as authorized by the respective regulatory authority.

Pro forma adjustments are made to recorded test year amounts that do not reflect the levels of expenses required for the provision of service, or that do not represent the levels expected to occur during the period when the new rates will be in effect. These adjustments may be made in the form of eliminations, annualizations, or normalizations.

Elimination adjustments are made to remove out-of-period or non-recurring transactions. Annualization adjustments are made to reflect the full, 12-month revenue or expense level of certain components of operating income. Annualization adjustments are typically computed using end-of-test-year quantities, and the most current known and measurable prices and rates.

Normalization adjustments reflect that the recorded test year operating revenues and expenses may not represent a normal level for rate-making purposes. Certain events may have affected recorded transactions in an atypical manner. Moreover, some transactions – while eligible for reflection in the revenue requirement – are incurred at intervals less frequent than annually, provide benefits extending beyond a single year, or reoccur in significantly different amounts each year. As a result, the amounts recorded in the test year may not be viewed as "normal", thus requiring adjustment for ratemaking purposes. Normalization adjustments are made in these instances when a test year level of revenues or expenses does not represent what would be expected on an on-going basis.

Q. **Were the pro forma adjustments that you are sponsoring in your testimony prepared by you or under your supervision?**

A. Yes, they were.

Q. **Have the pro forma adjustments for which you are responsible in this rate filing been computed in accordance with sound rate-making principles and applicable rules and policies of the Arizona Corporation Commission ("Commission")?**

A. Yes. To the best of my knowledge, all of the adjustments that I am sponsoring have been so calculated.

III. RATE BASE ADJUSTMENTS.

A. Accumulated Deferred Income Tax ("ADIT").

Q. Please explain the ADIT Adjustment.

A. The adjustment reduces rate base for the computed balance of ADIT, a source of non-investor capital, based on adjusted test-year rate base, test-year operating results, and the Company's existing income tax ratemaking authority.

Q. What are deferred income taxes?

A. Deferred income taxes represent the tax effect of differences that arise between the time period when revenues and expenses are recognized for financial reporting purposes and when they are considered for income tax return purposes. For public utilities, the largest such difference is that which exists as a result of using accelerated methods and shorter lives in computing tax depreciation, as compared with the manner in which book and regulatory depreciation is computed. The process of apportioning income taxes among accounting periods is often referred to as "inter-period income tax allocation," or "normalization".

Q. In order to better understand deferred income taxes, can you briefly describe the accounting for income taxes under GAAP?

A. Yes. Accounting for income taxes under GAAP is contained in the Accounting Standards Codification ("ASC") in Section 740 (formerly SFAS No. 109 *Accounting for Income Taxes* ("SFAS109")). The income tax calculation has three components: income taxes currently payable, deferred income taxes, and the ITC. Taxes currently payable represents the income taxes payable to the U.S. Treasury for the current period as computed under the provisions of the Internal Revenue Code ("IRC"). There are differences between how certain items are treated under the IRC and GAAP. These differences are listed on Schedule M of the filed income tax return. Such differences between income tax treatment and book accounting treatment are either "timing/temporary differences" or "permanent differences".

Timing/temporary differences represent differences between book income and taxable income that originate in one or more periods, and reverse or turn around, in one or more subsequent periods. Because of their capital intensity, the difference between book and tax depreciation is typically the largest timing difference affecting public utilities.

For book purposes, utility plant is capitalized and depreciated over the estimated useful life in a systematic and rational manner, typically straight-line. For income tax purposes, depreciation is computed over shorter lives using one of the accelerated methods contained in the IRC. Depreciation is generally considered a timing/temporary difference because both book and tax depreciation amounts are limited, over time, to the cost of the utility plant. Thus, in the early years tax depreciation will exceed book depreciation, but in the later years, book depreciation will exceed tax depreciation.

Other examples of timing/temporary differences include: (i) expenses that are deducted by utilities currently for tax purposes, but deferred on the books as regulatory assets for future recognition in rates (such as rate case expense); and (ii) expenses that are recognized for book purposes ahead of when they are deductible for income tax purposes (such as accrued vacation expense).

Permanent differences also exist between book income and taxable income, and do not reverse in subsequent periods. Examples of permanent differences include non-taxable interest income from municipal bonds and meals expense, which is only 50% deductible for income tax purposes. Both of these items are included when determining book income, but are never included in the determination of taxable income on the income tax return.

Q. How are the income tax components calculated?

A. Income taxes currently payable are calculated on the estimated liability incurred by the Company based on the current year's taxable income (using the rules under the IRC). Deferred income taxes are computed for timing/temporary differences, but not for permanent differences. Deferred income tax expense is calculated by multiplying timing/temporary difference by the statutory income tax rates in effect at the time the timing difference reverses. It should be noted that the typical effect of timing/temporary differences is to reduce current income taxes and increase deferred income taxes, dollar for dollar with no "net" impact on the calculation of total income taxes.

Q. How do deferred income taxes affect public utility rate-making?

A. The reflection of deferred income taxes in rate-making is commonly referred to as "normalization." Some utility regulatory agencies permit utilities to recognize deferred income taxes associated with all timing/temporary differences in rate-making ("full normalization"), while others only permit the recognition of certain timing/temporary differences required by the IRC to be recognized in utility ratemaking ("partial normalization"). To the extent that normalization is permitted in ratemaking, the resulting deferred income taxes are reflected as a component of income tax expense – with the corresponding balance sheet reserve for accumulated deferred taxes deducted from rate base as non-investor capital. This treatment reflects the availability of such amounts for plant investment or operating purposes between the time they are collected from customers and ultimately remitted to taxing authorities. In effect, the ADIT represents a cost-free or interest-free loan from the U.S. Treasury.

The other ratemaking approach to timing/temporary differences is when regulators do not permit deferred income tax expense as a recoverable cost in the ratemaking process. This approach is known as "flow through" since, under this approach, the income tax reducing benefits of tax return deductions are "flowed-through" to the retail customer by a reduction of current income tax expense, without the offsetting deferred income tax expense. Because flow-through only applies to book-tax timing/temporary differences, any reduction in income taxes payable when a timing/temporary difference originates is offset by higher income taxes payable when the timing/temporary difference reverses (turns around). Of course, under a flow-through approach, there is no net ADIT to reduce rate base as the "interest free" loan has been provided to retail customers.

Q. What income tax-related rate-making authority has been granted to UNS Electric by the ACC?

A. UNS Electric's assets were formerly owned by Citizens Communications Company, which operated various properties throughout the state of Arizona, with each having its separate designated service territory, rate schedules and service rules. For electric operations, Citizens operated separate divisions in northern Arizona and southern Arizona. The pro forma income tax expense calculations prepared for, and approved in the 1996 Citizens rate case (Decision No. 59951 (January 3, 1997)) used a full normalization of all book/tax-timing differences and were prepared on a combined basis for the two electric plant divisions. This combined-division basis and use of full normalization was affirmed for use in (i) Decision No. 66028 (July 3, 2003), which approved the acquisition of the systems by UNS Energy and the organization where electric assets would be owned by UNS Electric and (ii) in UNS Electric's most recent rate case order, Decision No. 74235 (December 31, 2013).

Q. Has there been a substantial change in ADIT since UNS Electric's last rate case?

A. Yes. UNS Electric's last rate case used a test year ending June 30, 2012. Since the last test year, the ADIT relating to accelerated depreciation has increased as a result of recent bonus depreciation legislation. On January 3, 2013, the "American Taxpayer Relief Act of 2012" was passed extending 50% bonus depreciation through December 31, 2013. On December 22, 2014, the "Tax Increase Prevention Act of 2014" was passed extending 50% bonus depreciation through December 31, 2014.

Q. Did UNS Electric elect bonus depreciation on all eligible property placed in service since the last rate case?

A. Yes. UNS Electric has claimed bonus depreciation on all eligible assets since the last rate case.

Q. Did all of the bonus depreciation deductions result in a cash benefit to UNS Electric through reduced Federal income tax payments?

A. No. The deductions for bonus depreciation exceeded the amount that could be used to offset taxable income and have created a Net Operating Loss Carryforward ("NOLC"). These excess deductions did not defer any Federal income tax liability and thus, under the tax depreciation normalization rules of Internal Revenue Code §168, such excess deductions should not be included in the Company's deferred income taxes.

Q. What are the tax depreciation normalization rules?

A. The tax depreciation normalization rules were enacted by Congress to prevent accelerated tax depreciation incentives from being flowed directly to customers through the rate setting process. The normalization rule requires that, where a utility claims accelerated depreciation it must make an adjustment to a reserve to reflect the amount of deferral of Federal income tax liability resulting from the use of such a depreciation method. In addition, the utility's ADIT reserve that can reduce rate base cannot exceed the amount of such reserve used in computing a utility's cost of service in ratemaking. By excluding the bonus depreciation deductions that were not used to offset taxable income from the computation of deferred income taxes, UNS Electric is in compliance with the normalization rules.

Q. What is the impact to UNS Electric and its customers if the tax depreciation normalization rules are not followed?

A. If the normalization rules are not followed, UNS Electric would not be able to claim accelerated tax depreciation. Instead, the Company would be required to use regulatory depreciation methods for tax purposes. This would cause a substantial increase in UNS Electric's income tax liabilities and a substantial decrease in the ADIT balance that is included as a reduction to rate base. As a consequence, the Company would have a higher rate base and higher rates than if normalization rules were followed.

Q. Has the IRS ruled on the normalization rules when a company has a NOLC?

A. Yes. In Private Letter Rulings ("PLRs") 201438003, 201436037, and 201436038 the IRS ruled that a reduction of a taxpayer's rate base by the full amount of its ADIT balance unreduced by the balance of its NOLC ADIT would be inconsistent with the normalization rules.

Q. Has UNS Electric reduced its ADIT rate base reduction by its NOLC ADIT?

A. Yes. To be consistent with the normalization rules UNS Electric has offset its ADIT rate base reduction by its NOLC ADIT.

B. Accumulated Deferred Investment Tax Credit ("ITC").

Q. You previously mentioned a third tax component to the income tax calculation, ITC. Please explain the adjustment for ITC.

A. Unlike deferred taxes, which can be likened to an interest-free loan from the U.S. Treasury, the ITC can be likened to a grant or rebate. The ITC is a direct reduction of income taxes otherwise payable. It is calculated by multiplying a qualifying investment times a statutory credit percentage.

As explained below, for rate-making purposes UNS Electric shares the ITC in accordance with IRC §46(f)(1), whereby the rate-making treatment for ITC is a reduction to rate base that reflects the provision of non-investor capital due to a reduction in income taxes payable (benefitting the customer) with below-the-line amortization (benefitting the shareholder) each year. UNS Electric has claimed ITC under IRC §48(a)(2) that provides for a 30% ITC for investment in qualifying solar facilities placed in service prior to January 1, 2017. Further, IRC §50(c)(3)(A) requires that the depreciable tax basis of the underlying property be reduced by an amount equal to 50% of the energy credit taken with regard to the property.

Q. What are the rules governing the accounting for ITC for public utilities?

A. The tax normalization rules are contained in IRC §46(f) (as in effect prior to the Revenue Reconciliation Act of 1990). IRC §50(d)(2) requires that these normalization rules be applied to the §48 Energy Credit when elected by a regulated utility. The normalization rules require all public utilities to elect one of the two available normalization methods. The method used by UNS Electric is described in §46(f)(1) (as in effect prior to the Revenue Reconciliation Act of 1990).

Q. Please explain the requirements of IRC §46(f)(1).

A. This section provides that a regulated utility shall not reduce the base to which rate of return is applied by any portion of the credit unless the reduction is restored not less rapidly than ratably. "Ratably" is defined as the life used by the public utility for purposes of calculating book depreciation for the qualified property.

Q. What is the amortization period used by UNS Electric to amortize ITC?

A. Consistent with UNS Electric's most recent rate case order, Decision No. 74235, ITC is amortized over the tax life of the assets that generated the ITC. In the case of solar generating facilities, the property is classified for depreciation purposes in IRC §168(e)(3)(B)(vi) and qualifies for a five-year life for tax depreciation purposes. As the book life of the solar generating assets is 20 years, the use of the shorter life is in compliance with the normalization provisions of IRC §46(f)(1).

Q. How do the normalization rules apply to taxpayers that have generated ITC, but have not yet realized the ITC benefit through lower income tax payments?

A. PLR 8326081 addresses the issue of when the benefits of ITC should be reflected in rates and concluded that if the ITC is used to reduce revenue requirements before actually realized on the income tax return, a normalization violation would occur. While this ruling is for a utility that elected the ITC sharing method provided for in §46(f)(2) (ratable amortization in cost of service), similar guidance should apply for utilities who elected to share ITC under §46(f)(1). In this ruling, the IRS clearly states "the credit cannot be used to reduce the cost of service until it has been allowed for federal income tax purposes". In the ruling, the taxpayer was prohibited from reducing cost of service that provides benefits to ratepayers. In the case of a company subject to the normalization provisions of §46(f)(1), such as UNS Electric, the same rule would apply to prohibit the reduction of rate base for credits not yet realized on the taxpayer's federal tax return.

Q. Please discuss the ITC UNS Electric has generated and how it has been treated in this rate case.

A. UNS Electric generated ITC in 2011 with the completion of the 1 MW La Senita Facility in Mohave County and again in 2014 with the completion of the 7 MW Rio Rico Facility in Santa Cruz County. The ITC generated in 2011 has been realized and the unamortized portion of the 2011 credit has been included as a reduction to rate base. The ITC generated in 2014 has not been realized and consistent with the normalization rules is not included as a reduction to rate base.

Q. Is there a corresponding adjustment to current or deferred income tax expense as a result of the ITC?

A. Yes, there is an adjustment to deferred income tax expense as a result of the ITC discussed later in my testimony.

IV. OPERATING INCOME ADJUSTMENTS.

A. Property Tax Expense.

Q. Please explain the Property Tax adjustment.

A. The Property Tax adjustment is a pro forma adjustment to test-year operating expense to reflect the final, adjusted plant in service at the end of the test year, using the 2016 statutory assessment ratio of 18%, and average expected property tax rates on the 2015 property tax bills. The Company will update its pro forma adjustment with actual 2015 property tax rates in October 2015 after property tax bills have been received and processed.

Q. Has UNS Electric changed the way it computes the Property Tax adjustment since the last rate case?

A. Yes. In the last rate cases of TEP and UNS Gas, Staff recommended the "actual" approach be used instead of the "standalone" approach. TEP and UNS Gas accepted the recommendation of Staff in resolving their respective rate cases. To establish a consistent approach across all of its affiliates UNS Electric used the "actual" approach in this rate case.

Q. Please elaborate on the difference between the "actual" approach and the "standalone" approach.

A. UNS Electric, together with its affiliates TEP and UNS Gas file a combined property tax return under UNS Energy. As a result of the combined filing, each company's property tax is different than it would be had each filed a standalone tax return. The "standalone" approach computes a pro forma property tax as if standalone returns had been filed, thus eliminating the influence each has on each other's property tax bills. The "actual" approach uses the actual combined filing.

B. Income Tax Expense.

Q. Please explain the Income Tax Expense adjustment.

A. The Income Tax Expense adjustment is a pro forma adjustment to test-year operating expenses to reflect income taxes based on final adjusted operating revenues, operating expenses, and rate base. It is computed in two parts. The first part is pro forma current income tax expense, with the tax liability computed as though an actual income tax return was being prepared on final adjusted test year taxable operating income. For this purpose, it was necessary to identify all operating book-tax differences ("Schedule M items"), both timing and permanent, and then re-compute current tax expense based on adjusted test year operating revenues and expenses as necessary. The tax deduction for interest was computed using a synchronization methodology reflecting final adjusted rate base and the weighted cost of debt in the capital structure.

The second part of the income tax adjustment is deferred income tax expense. Deferred income taxes are computed on the Schedule M items representing timing differences for which UNS Electric has obtained normalization ratemaking authority from the Commission as previously described in my direct testimony.

Q. What is the adjustment to Deferred Income Tax Expense as a result of the basis adjustment associated with the IRC §48 Energy Credit?

A. As previously discussed in my direct testimony, the election to take the §48 Energy Credit on qualifying property requires a reduction in the basis of the qualifying property for purposes of calculating tax depreciation. The result of this basis reduction is that future tax depreciation deductions will be reduced by an amount equal to one-half of the §48 Energy Credit, or 15% of the basis of the qualifying property.

This basis reduction effectively reduces the value of the §48 Energy Credit from 30% of the cost of the asset (the amount of the unamortized rate-base reduction) to 24.75% (assuming a 35% tax rate applied to the 15% basis reduction). This loss of benefit is reflected as an increase to deferred income tax expense each year as the basis difference reverses through the book depreciation timing difference. This treatment is consistent with UNS Electric's most recent rate case order, Decision No. 74235.

Q. Are there any adjustments to deferred income tax expense as a result of the phased in Arizona income tax rate reduction passed in 2011?

A. Yes. When timing/temporary differences reverse at an income tax rate that is lower than the rate that was in effect when the timing/temporary differences originate excess deferred income taxes are created. Excess deferred taxes reduce retail customer rates on the same schedule that the taxes would have been paid to the state of Arizona, if the income tax rates had not been reduced. In other words, the excess deferred income taxes will be amortized as a reduction to deferred income tax expense as the underlying timing differences reverse. This treatment is consistent with UNS Electric's most recent rate case order, Decision No. 74235.

V. PROPERTY TAX DEFERRAL.

Q. Please describe the Company's property tax deferral proposal.

A. UNS Electric is requesting authority to defer 100% 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, UNS Electric is requesting authority to defer all costs associated with appealing Gila River property values.

Q. Please explain why the Company is requesting a property tax deferral related to changes in composite tax rates.

A. Property taxes are a function of property values and budgets within a particular taxing jurisdiction. As property values fall, taxing authorities must raise tax rates to maintain revenues. Total property values in Mohave and Santa Cruz Counties have seen steep declines in recent years. The table below shows the total net assessed valuation and the percentage change from the prior tax year.

Tax Year	Mohave County	Mohave % Change	Santa Cruz County	Santa Cruz % Change
2010	$2,321,464,632	-	$411,470,857	-
2011	$1,932,681,722	-16.7%	$382,619,719	-7.0%
2012	$1,791,765,155	-7.3%	$369,498,126	-3.4%
2013	$1,771,371,872	-1.1%	$338,356,662	-8.4%
2014	$1,727,793,369	-2.5%	$320,999,663	-5.1%

As a result of these declines property tax rates have risen significantly over the same period. The table below shows the rise in the primary county tax rate and the percentage change from the prior tax year.

Tax Year	Mohave County	Mohave % Change	Santa Cruz County	Santa Cruz % Change
2010	2.6067	-	3.2478	-
2011	3.2234	23.7%	3.3173	2.1%
2012	3.3864	5.1%	3.3631	1.4%
2013	3.4843	2.9%	4.3538	29.5%
2014	3.5500	1.9%	4.6037	5.7%

For most taxpayers lower values and higher tax rates would not necessarily change the taxpayer's tax payment. For UNS Electric, however, the assessed value is based primarily on the book value of its fixed assets, a value that is typically rising because UNS Electric's annual capital expenditures tend to exceed the total annual depreciation expense. As a result, when a taxing authority raises rates, UNS Electric's tax payment rises accordingly. UNS Electric is concerned that these trends will continue and the test year level of property tax expense in this case will fall well short of actual tax payments, as it has since the last rate case.

In UNS Electric's last rate case test year property tax expense was based on a 10.0087% composite tax rate from its 2012 tax bills. UNS Electric's tax year 2013 and 2014 composite rates were 10.7666% and 11.0625% and the estimated composite rate for 2015 excluding the impact of the Gila River acquisition is 11.5599% representing a 15.5% increase from UNS Electric's last test year. UNS Electric requests authority to defer 100% of the property taxes above or below the test year caused by increases or decreases in the composite tax rate.

Q. Please explain why the Company is requesting a property tax deferral related to changes in the Gila River valuation methodology along with the costs of appealing the Gila River value.

A. Arizona property tax law related to valuation of generation facilities provides in part that:

> *"In the case of a facility that is acquired from another taxpayer:*
>
> *If, after the acquisition, the buyer has possession of the cost information, the valuation of the facility shall continue based on the seller's cost as if there were no change in ownership.*
>
> *If, after the acquisition, the buyer does not possess the cost information, the acquisition cost in an arm's length transaction shall be used."*

With respect to the Gila River Power Station as a whole the Arizona Department of Revenue ("ADOR") has taken the position that buyers cannot use the cost information of

Gila River Power, LLC, the seller, as it is not the original owner. Thus, ADOR will determine the full cash value UNS Electric's share of Gila River generation assets at the purchase price of approximately $50 million. Property taxes in this case are based on this $50 million full cash value. For transmission assets and materials & supplies acquired as part of the Gila River acquisition full cash value is equal to net book value while intangibles will not be subject to tax.

ADOR has interpreted "seller's cost" to mean "the original cost of the original owner" while UNS Electric interprets the law to mean "sellers cost as reported on the property tax returns immediately prior to acquisition". The difference between these interpretations is significant with UNS Electric's approach yielding a full cash value of $29 million; $21 million lower than ADOR. UNS Electric plans on appealing the ADOR full cash value when it is issued this summer and could incur significant costs disputing the value. The appeal process is expected to take several years. While the appeal process proceeds UNS Electric will be required to make tax payments based on the higher $50 million full cash value determined by ADOR. UNS Electric believes property tax benefits obtained from a successful appeal along with the associated costs should benefit ratepayers. Thus, UNS Electric requests authority to defer property tax savings derived from appealing the Gila River full cash value along with all costs associated with the appeal process.

Q. **Has the Arizona Corporation Commission ever granted a property tax deferral?**

A. Yes. In Decision No. 73183 (May 24, 2012), the Commission approved the rate case settlement agreement that provided for a property tax deferral for Arizona Public Service Company.

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

A. 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
7) Deferral: Gila Value Reduction (2 x 5)	($424,760)
8) Deferral: Appeal Expenses**	$25,000
9) Total Deferral (6 + 7 + 8)	$309,651

*$21 million possible reduction in full cash value multiplied by 18% assessment ratio

**For illustrative purposes only

Q. How will the property tax deferral be amortized?

A. Beginning on the effective date of the Company's next rate case the deferral balance, whether positive or negative will be amortized over 3 years.

Q. Will the property tax deferral affect the revenue requirement in this rate case?

A. No, it will not.

VI. GILA RIVER GENERATING STATION ACQUISITION ACCOUNTING.

Q. Please describe the Gila River Generating Station Acquisition Accounting.

A. As discussed more fully in the Direct Testimony of Mike Sheehan, UNS Electric acquired Gila River in December 2014 for approximately $55 million. Most companies would simply record $55 million as plant in service. However, under the FERC Uniform System of Accounts, Electric Plant Instruction Number 5, Electric Plant Purchased or Sold, acquiring utilities are required to record:

- The original cost of plant
- The depreciation and amortization applicable to the original cost
- Acquisition premium or discount for the difference between the amount paid and the net book value of the plant acquired.

In compliance with this provision, UNS Electric recorded the following with respect to the Gila River acquisition:

Closing Overview	
Funds Paid at Closing	$54,646,024
Plus: Acquisition Expenses	$162,728
Less: Prorated Expenses Paid at Closing	$30,992
Net Purchase Price	$54,777,760
Allocation of Net Purchase Price	
Plant in Service – Original Cost	$90,964,426
Accumulated Reserve	($21,788,832)
Acquisition Discount	($14,939,365)
Materials & Supplies	$541,531
Net Purchase Price	$54,777,760

Q. How does this acquisition accounting impact the revenue requirement in this rate case?

A. The net purchase price of $54,777,760, less December 2014 depreciation expense of $84,355 ($54,693,405) has been included in the calculation of rate base.

Q. Does this conclude your Direct Testimony?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE – INTERIM CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
VACANT

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

EXHIBIT
UNSE-15
ADMITTED

Rebuttal Testimony of

Jason J. Rademacher

on Behalf of

UNS Electric, Inc.

January 19, 2016

Table of Contents

Exhibits

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Jason Rademacher and my business address is 88 East Broadway, Tucson, Arizona, 85702.

Q. Did you file Direct Testimony in this proceeding?

A. Yes.

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

A. My Rebuttal Testimony is filed on behalf of UNS Electric, Inc. ("UNS Electric" or the "Company").

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

A. My Rebuttal Testimony addresses the Direct Testimony of Jeffrey M. Michlik on behalf on the Residential Utility Consumer Office ("RUCO").

II. NET OPERATING LOSS CARRYFORWARD ("NOLC").

Q. Has RUCO proposed an adjustment to remove UNS Electric's NOLC ADIT from rate base?

A. Yes. RUCO recommends increasing the ADIT balance by $7,467,062 from $35,161,108 to $42,628,170.

Q. Please explain what NOLC ADIT is.

A. An ADIT credit balance is typically included as a reduction to rate base in setting rates because it represents an interest-free loan from the government and a source of non-investor capital. The ADIT credit balance is generated primarily through the difference between accelerated tax depreciation and regulatory depreciation methods. NOLC ADIT is the recognition that the company did not receive an interest-free loan from the government for the full amount of the depreciation difference. The ADIT credit balance generated from accelerated depreciation is offset by a NOLC ADIT balance to reflect the actual interest-free loan obtained by the Company.

Q. Please summarize why UNS Electric included NOLC ADIT in rate base.

A. In order to retain and continue to claim valuable accelerated tax depreciation deductions which reduce rate base and customer rates, UNS Electric was required to include the NOLC ADIT under Internal Revenue Code ("IRC") §168, and the rules adopted thereunder.

Q. Please explain how IRC §168 places such a requirement on UNS Electric.

A. I discuss the IRS normalizations in detail on pages 8 and 9 of my Direct Testimony. The rules limit the accelerated depreciation ADIT rate base reduction to the amount of Federal income tax liability deferred from using accelerated depreciation methods. Simply put, only the ADIT that reduced taxable income to $0 can reduce rate base. If the normalization rules are not followed, a utility is not allowed to claim accelerated depreciation. The utility would be required to use straight line regulatory depreciation methods, which do not create any ADIT. Violating the normalization rules would harm customers by increasing rate base and increasing customer rates.

Q. How is UNS Electric certain that the normalization rules under §168 apply to NOLCs?

A. As a result of bonus depreciation allowed by Congress, many utilities are in the same position as UNS Electric and have large NOLCs. There have been several instances where a utility and their respective state commissions are uncertain as to whether the regulatory treatment of NOLCs is following the normalization rules. As a result, Private Letter Rulings ("PLR's) have been requested from the IRS. Each PLR is specific to the facts and circumstances of the utility and its commission's treatment of NOLC's. As I stated in my Direct Testimony on page 9, line 17, 3 PLR's had been issued for the NOLC issue. In each case the IRS ruled that a reduction of a taxpayer's rate base by the full amount of its ADIT balance (i.e. not reduced by the balance of its NOLC ADIT) would be a violation of the normalization rules. These three PLR's along with 3 others that I refer to later in my testimony have been attached as **Exhibit JJR-R-1**.

Q. Have there been additional PLRs issued since UNS Electric filed its rate case?

A. Yes. The IRS has issued PLRs 201519021 and 201534001. In both, the IRS again ruled that a reduction of a taxpayer's rate base by the full amount of its ADIT balance unreduced by the balance of its NOLC ADIT would be a violation of the normalization rules.

Q. Is UNS Electric's treatment of NOLC's in compliance with the five PLRs you refer to?

A. Yes. UNS Electric's treatment of the NOLC is consistent with the PLRs, is consistent with the normalization rules, and will allow the Company to retain and continue to claim accelerated depreciation deductions for the benefit of customers.

Q. Is RUCO's proposed removal of the NOLC ADIT from rate base consistent with the PLRs?

A. No. Based on the PLRs, RUCO's approach would violate the normalization rules, would eliminate the Company's ability to claim accelerated depreciation, would reduce or eliminate the ADIT rate base reduction in future rate cases, and harm customers.

Q. RUCO mentions a 6th PLR that you have not yet referred to, PLR 201418024 ("6th PLR"). What did the IRS rule in this 6th PLR?

A. The IRS ruled that excluding the NOLC did not violate the normalization rules.

Q. Why did you exclude this ruling from your Direct Testimony?

A. This PLR addresses a different situation. Specifically, the method of computing deferred income tax expense in the 6th PLR is not consistent with how UNS Electric computed deferred income tax expense in this rate case or in any prior rate case. In addition, it is inconsistent with how UNS Electric's affiliates, Tucson Electric Power and UNS Gas, have computed deferred income tax expense in prior rate cases. Further, UNS Electric is not aware of the Commission approving deferred income tax expense calculated in the manner presented in the 6th PLR in any rate case.

Q. What does the 6th PLR state with respect to the calculation of deferred income tax expense?

A. The ruling contains the following language:

> "Both Commission and Taxpayer have intended, at all relevant times, to comply with the normalization requirements. Commission has stated that, in setting rates it includes a provision for deferred taxes based on the entire difference between accelerated tax and regulatory depreciation, including situations in which a utility has an NOLC or MTCC. Such a

provision allows a utility to collect amounts from ratepayers equal to income taxes that would have been due absent the NOLC and MTCC. Thus, Commission has already taken the NOLC and MTCC into account in setting rates.

Q. If deferred income tax is calculated "based on the entire difference between accelerated depreciation and regulatory depreciation", the ruling allows the NOLC ADIT to be excluded from rate base?

A. Yes. The ruling contains the following language:

> We therefore conclude that the reduction of Taxpayer's rate base by the full amount of its ADIT account without regard to the balances in its NOLC-related account and its MTCC-related account was consistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations."

Q. Did UNS Electric calculate deferred income tax "based on the entire difference between accelerated depreciation and regulatory depreciation?"

A. No, UNS Electric calculates deferred income tax only on the portion of accelerated depreciation that reduces taxable income to $0. As I state later in my Direct Testimony, the deferred income tax on the difference between accelerated depreciation and regulatory depreciation was $0.

Q. Did RUCO calculate deferred income tax "based on the entire difference between accelerated depreciation and regulatory depreciation?"

A. No. RUCO introduces the 6th PLR as support for its position to remove the NOLC ADIT, but then violates the deferred income tax expense calculation requirement of the ruling.

Q. Should the Commission calculate deferred income tax expense "based on the entire difference between accelerated depreciation and regulatory depreciation?"

A. No. Doing so would unnecessarily increase deferred income tax expense and the overall revenue requirement.

Q. What is the deferred income tax expense on "the entire difference between accelerated depreciation and regulatory depreciation"?

A. As shown on page 3 of the Income – Income Taxes.pdf pro forma adjustments workpapers, Deferred Fed column, tax depreciation is $45,579,823 and regulatory depreciation is $13,953,220 resulting in a difference of $31,626,603. The Federal deferred income tax on this difference would be $10,753,045 ($31,626,603 x 34% Federal Tax Rate) on a total company basis, or $8,192,745 on an ACC jurisdiction basis.

Q. How much deferred income tax expense did UNS Electric include in this rate case for "the entire difference between accelerated depreciation and regulatory depreciation".

A. As shown on Schedule C-1 of UNS Electric's filing, the total deferred income tax expense included in this rate case was $1,291,000. Of that amount, $0 relates to the difference between accelerated depreciation and regulatory depreciation. As shown on page 8 of the Income – Income Taxes.pdf pro forma adjustments workpapers UNS Electric had a $35,045,106 loss for income tax purposes. Since the income tax loss exceeds the $31,626,603 difference between tax and regulatory depreciation, the deferred income tax on the depreciation difference was $0. To be in compliance with the 6th PLR, an additional $8,192,745 would need to be added to deferred income tax expense. Clearly, a deferred income tax expense increase of $8,192,745 far exceeds the revenue requirement impact of reducing rate base by the $7,467,062 NOLC ADIT.

Q. Is RUCO's proposal to remove the NOLC ADIT without a corresponding deferred income tax expense adjustment a normalization violation?

A. Yes. RUCO must include the $7,467,062 NOLC ADIT in rate base or it must add $8,192,745 to income tax expense. Excluding both is a normalization violation.

Q. RUCO claims that the Commission is not bound by the IRS code or GAAP. How do you respond to this claim?

A. They are not relevant as it relates to this issue. The issue is how the treatment of the NOLC ADIT in a rate case proceeding impacts the Company's ability to claim accelerated depreciation and maximize tax deductions for the benefit of customers. As I demonstrated above, RUCO's proposal is a normalization violation and would result in a loss of accelerated depreciation tax deductions. It would harm ratepayers.

Q. Does UNS Electric's inclusion of NOLC ADIT in rate base provide the most benefit to customers?

A. Yes. UNS Electric's inclusion of NOLC ADIT is the only way to maximize customer benefits from accelerated depreciation in this rate case and in future rate cases.

III. PROPERTY TAX.

Q. Did RUCO accept the Property Tax Deferral as proposed on pages 15-19 of your Direct Testimony?

A. No. RUCO bifurcates the deferral and rejects the proposal to defer 100% of the Arizona property taxes above or below the test year level caused by changes in the composite tax rate. RUCO recommends a 50/50 sharing between shareholders and ratepayers for the benefits and costs from appealing Gila River property values. In addition, RUCO proposes a cap on the costs associated with the Gila River appeal.

Q. Why does RUCO reject the tax rate component of the deferral?

A. RUCO claims on page 36, line 15 of Mr. Michlik's Direct Testimony that, "There is nothing extraordinary about the Company's request for a deferral of property taxes in this case, other than APS received one."

Q. How do you respond to this claim?

A. RUCO misses the "extraordinary" aspect of the Property Tax Deferral by attempting to bifurcate the deferral into two components. The potential benefits from the Gila River appeal is what makes UNS Electric's total proposal unique and potentially a benefit for ratepayers.

Q. Mr. Michlik claims on page 37, line 6 that the Gila River appeal will save the Company's shareholders money in the long-term. Is this accurate?

A. No. Property taxes are one of expense categories included in cost of service. Shareholders can benefit in between rate cases if property taxes decrease from the test year level. However, that shareholder benefit is short lived. It can help delay the filing of a rate case, but when a rate case is filed those benefits are forever passed onto customer.

Q. In the absence of a deferral mechanism, would shareholders benefit if UNS Electric is successful in its Gila River appeal?

A. Yes, but only until UNS Electric's next rate case. From that point forward, ratepayers would receive 100% of the benefits from lower Gila River property values. If UNS Electric's proposal were approved, customers would start receiving 100% of the benefits immediately and not have to wait until the next rate case.

Q. If UNS Electric loses its appeal, why should ratepayers cover the costs?

A. Since ratepayers will benefit over the entire 35 year remaining life of the Gila River plant with a successful appeal, it is appropriate for the ratepayers to cover 100% of the costs even if UNS Electric is not successful.

Q. RUCO proposes a cap on expenses. Is this reasonable?

A. No. Projecting how hard the Arizona Department of Revenue ("ADOR") will fight and how many levels of court UNS Electric will have to work through would be difficult if not impossible.

Q. What factors should the Commission be aware of that will mitigate costs?

A. UNS Electric is not the first to litigate Gila River property tax values with the ADOR. Sun Devil Holdings, the owners of Gila River Block 1 & 2, are already in Tax Court litigating the same exact issue UNS Electric plans to litigate.

Q. How does the Sun Devil litigation mitigate UNS Electric's costs?

A. If Sun Devil wins its case, the Tax Court should not need to devote as much effort to hearing interpretations of statutes from UNS Electric and the ADOR. Precedent will have been set and UNS Electric's focus would be on proving that its facts are the same as Sun Devil's. If Sun Devil loses, UNS Electric has the opportunity to drop its case and avoid further litigation costs.

Q. If UNS Electric prevails, will its costs be covered by the ADOR?

A. Recovery of legal fees and expenses in tax cases is discretionary under A.R.S. §12-348(B), and is subject to the maximum hourly fee specified in A.R.S. §12-348(E)(3) and the maximum total amounts in A.R.S. §12-348(E)(5), subject to the inflation adjustment specified in A.R.S. §12-348(E)(6). Any amounts that are recovered from the ADOR under these statutes will be included as a credit to the Property Tax Deferral. While some costs may be covered, UNS Electric does not expect 100% of its outside services costs to be recovered from the ADOR.

Q. Should RUCO's Property Tax Deferral changes be accepted?

A. No, the Property Tax Deferral as originally proposed in my Direct Testimony are in the public interest and should be accepted by the Commission.

Q. Does this conclude your Testimony?

A. Yes, it does.

Exhibit JJR-R-1

Checkpoint Contents
Federal Library
Federal Source Materials
IRS Rulings & Releases
Private Letter Rulings & TAMs, FSAs, SCAs, CCAs, GCMs, AODs & Other FOIA Documents
Private Letter Rulings & Technical Advice Memoranda (1950 to Present)
2014
PLR/TAM 201418067 - 201418001
PLR 201418024 -- IRC Sec(s). 168, 05/02/14

Private Letter Rulings

Private Letter Ruling 201418024, 05/02/14, IRC Sec(s). 168

UIL No.

Accelerated cost recovery system-rate base calculations-normalization rules-consistency requirements-public utilities.

Headnote:

Commission's reduction of public utility's rate base by full amount of its accumulated deferred income tax without regard to balances in its net operating loss carryforward account and its minimum tax credit carryforward account was consistent with normalization requirements of **Code Sec. 168(i)(9)**; and **Reg § 1.167(l)-1** .

Reference(s): **Code Sec. 168;**

Full Text:

Number: **201418024**

Release Date: 5/2/2014

Index Number: 167.22-01

Third Party Communication: None

Date of Communication: Not Applicable

Person To Contact: [Redacted Text]

[Redacted Text], ID No.

Telephone Number: [Redacted Text]

Refer Reply To:

CC:PSI:B06

PLR-133813-13

Date:

January 27, 2014

LEGEND:

Taxpayer =

Parent =

State =

Commission =

Year A =

Year B =

Year C =

Year D =

Year E =

X =

Y =

Date A =

Date B =

Date C =

Date D =

Date E =

Case =

Director =

Dear [Redacted Text]:

This letter responds to the request, dated July 30, 2013, of Taxpayer for a ruling on whether the Commission's treatment of Taxpayer's Accumulated Deferred Income Tax (ADIT) account balance in the context of a rate case is consistent with the requirements of the normalization provisions of the Internal Revenue Code.

The representations set out in your letter follow.

Taxpayer is a regulated public utility incorporated in State. It is wholly owned by Parent. Taxpayer distributes and sells natural gas to customers in State. Taxpayer is subject to the regulatory jurisdiction of Commission with respect to terms and conditions of service and particularly the rates it may charge for the provision of service. Taxpayer takes accelerated depreciation where available and, for the period beginning in Year A and ending in Year E, Taxpayer has, in the aggregate, produced more net operating losses (NOL) than taxable income. After application of the carryback and carryforward rules, Taxpayer represents that it has net operating loss carryforward (NOLC), produced in Year C and Year E, of $X as of the end of Year E. The amount of claimed accelerated depreciation in Year C and Year E exceeded the amount of the NOLCs for those years. In Year D, Taxpayer produced regular taxable income as well as alternative minimum taxable income (AMTI); the regular taxable income was offset by the NOLCs from Year B and year C but could not offset the entire alternative minimum tax (AMT) liability due to the limitation in § 56(d). Taxpayer paid $Y of AMT in Year D and had a minimum tax credit carryforward (MTCC) as of the end of year E of $Y.

On its regulatory books of account, Taxpayer "normalizes" the differences between regulatory depreciation and tax depreciation. This means that, where accelerated depreciation reduces taxable income, the taxes that a taxpayer would have paid if regulatory depreciation (instead of accelerated tax depreciation) were claimed constitute "cost-free capital" to the taxpayer. A taxpayer that normalizes these differences, like Taxpayer, maintains a reserve account showing the amount of tax liability that is deferred as a result of the accelerated depreciation. This reserve is the accumulated deferred income tax (ADIT) account. Taxpayer maintains an ADIT account and also maintains an offsetting series of entries that reflect that portion of those `tax losses' which, while due to accelerated depreciation, did not actually defer tax because of the existence of an NOLC. With respect to the $Y AMT liability from Year D, Taxpayer carried that amount as an offset to the ADIT because the AMT increased the payment of tax.

Taxpayer filed a general rate case on Date A (Case). The test year used in the Case was the 12 month period ending on Date B. In establishing the income tax expense element of its cost of service, the tax benefits attributable to accelerated depreciation were normalized in accordance with Commission policy and were not flowed thru to ratepayers. In establishing the rate base on which Taxpayer was to be allowed to earn a return Commission generally offsets rate base by Taxpayer's plant based ADIT balance, using a 13-month average of the month-end balances of the relevant accounts. Taxpayer argued that the ADIT balance should be reduced by the amounts that Taxpayer calculates did not actually defer tax due to the presence of NOLCs or the AMT. Commission, in an order issued on Date C, did not use the amounts that Taxpayer calculates did not defer tax due to NOLCs or AMT but only the amount in the ADIT account. Taxpayer filed a petition for reconsideration based on the normalization implications of the order. On Date D, Commission rejected Taxpayer's request. Taxpayer again requested reconsideration and the Commission denied that request on Date E. Commission asserts that, in setting rates it includes a provision for deferred taxes based on the entire difference between accelerated tax and regulatory depreciation, including situations in which a utility has, such as in this case, an NOLC or AMT. Thus, Commission asserts that it has already recognized the effects of the NOCL in setting rates and there is no need to reduce the ADIT by the other amounts due to NOLCs or AMT.

Taxpayer requests that we rule as follows:

Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account without regard to the balances in its NOLC-related account and its MTCC-related account was consistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

Law and Analysis

Section 168(f)(2) of the Code provides that the depreciation deduction determined under section 168 shall not apply to any public utility property (within the meaning of section 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, section 168(i)(9)(A)(i) of the Code requires the taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under section 168(i)(9)(A)(ii), if the amount allowable as a deduction under section 168 differs from the amount that-would be allowable as a deduction under section 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under section 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) of the Code provides that one way the requirements of section 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under section 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under section 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base.

Former section 167(l) of the Code generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former section 167(l)(3)(G) in a manner consistent with that found in section 168(i)(9)(A). Section 1.167(1)-1(a)(1) of the Income Tax Regulations provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under section 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 1.167(l)-1(h)(1)(i) provides that the reserve established for public utility property should reflect the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes.

Section 1.167(1)-1(h)(1)(iii) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the amount of the actual tax liability. This amount shall be taken into account for the taxable year in which the different methods of depreciation are used. If, however, in respect of any taxable year the use of a method of depreciation other than a subsection (1) method for purposes of determining the taxpayer's reasonable allowance under section 167(a) results in a net operating loss carryover to a year succeeding such taxable year which would not have arisen (or an increase in such carryover which would not have arisen) had the taxpayer determined his reasonable allowance under section 167(a) using a subsection (1) method, then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director.

Section 1.167(1)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. This regulation further provides that, with respect to any account, the aggregate amount allocable to deferred tax under section 167(1) shall not be reduced except to reflect the amount for any taxable year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation. That section also notes that the aggregate amount allocable to deferred taxes may be reduced to reflect the amount for any taxable year by which federal income taxes are greater by reason of the prior use of different methods of depreciation under section 1.167(1)-1(h)(1)(i) or to reflect asset retirements or the expiration of the period for depreciation used for determining the allowance for depreciation under section 167(a).

Section 1.167(1)-(h)(6)(i) provides that, notwithstanding the provisions of subparagraph (1) of that paragraph, a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking.

Section 1.167(1)-(h)(6)(ii) provides that, for the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under subdivision (i), above, if solely an historical period is used to determine depreciation for Federal income tax expense for ratemaking purposes, then the amount of the reserve account for that period is the amount of the reserve (determined under section 1.167(1)-1(h)(2)(i)) at the end of the historical period. If such determination is made by reference both to an historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period.

Section 55 of the Code imposes an alternative minimum tax on certain taxpayers, including corporations. Adjustments in computing alternative minimum taxable income are provided in § 56.

Section 56(a)(1) provides for the treatment of depreciation in computing alternative minimum taxable income. Section 56(a)(1)(D) provides that, with respect to public utility property the Secretary shall prescribe the requirements of a normalization method of accounting for that section.

Section 1.167(l)-1(h) requires that a utility must maintain a reserve reflecting the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes. Taxpayer has done so. Section 1.167(1)-(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Section 56(a)(1)(D) provides that, with respect to public utility property the Secretary shall prescribe the requirements of a normalization method of accounting for that section.

In the rate case at issue, Commission has excluded from the base to which the Taxpayer's rate of return is applied the reserve for deferred taxes, unmodified by the accounts which Taxpayer has designed to calculate the effects of the NOLCs and MTCC. There is little guidance on exactly how an NOLC or MTCC must be taken into account in calculating the reserve for deferred taxes under §§ 1.167(1)-1(h)(1)(iii) and 56(a)(1)(D). However, it is clear that both must be taken into account in calculating the amount of the reserve for deferred taxes (ADIT) for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking.

Both Commission and Taxpayer have intended, at all relevant times, to comply with the normalization requirements. Commission has stated that, in setting rates it includes a provision for deferred taxes based on the entire difference between accelerated tax and regulatory depreciation, including situations in which a utility has an NOLC or MTCC. Such a provision allows a utility to collect amounts from ratepayers equal to income taxes that would have been due absent the NOLC and MTCC. Thus, Commission has already taken the NOLC and MTCC into account in setting rates. Because the NOLC and MTCC have been taken into account, Commission's decision to not reduce the amount of the reserve for deferred taxes by these amounts does not result in the amount of that reserve for the period being used in determining the taxpayer's expense in computing cost of service exceeding the proper amount of the reserve and violate the normalization requirements. We therefore conclude that the reduction of Taxpayer's rate base by the full amount of its ADIT account without regard to the balances in its NOLC-related account and its MTCC-related account was consistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

This ruling is based on the representations submitted by Taxpayer and is only valid if those representations are accurate.

Except as specifically determined above, no opinion is expressed or implied concerning the Federal income tax consequences of the matters described above. In particular, while we accept as true for purposes of this ruling Commission's assertions that it includes a provision for deferred taxes based on the entire difference between accelerated tax and regulatory depreciation, including situations in which a utility has an NOLC or AMT, we do not conclude that it has done so and those assertions are subject to verification on audit.

This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent. In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative. W e are also sending a copy of this letter ruling to the Director.

Sincerely,

Peter C. Friedman

Senior Technician Reviewer, Branch 6

(Passthroughs & Special Industries)

cc: [Redacted Text]

Private Letter Rulings

Private Letter Ruling 201436037, 09/05/14, IRC Sec(s). 167

UIL No. 167.22-01

Accelerated depreciation-accumulated deferred income tax-net operating loss carryover-computation based on with or without basis-normalization-limitations on reasonable allowance in case of property of public utilities.

Headnote:

Reduction of regulated electric utility's rate base by full amount of its ADIT account balances offset by portion of its NOLC-related account that is less than amount attributable to accelerated depreciation computed on "with or without" basis would be inconsistent with **Code Sec. 168(i)(9)**; and **Reg § 1.167(l)-1** requirements.

Reference(s): **Code Sec. 167; Code Sec. 168;**

Full Text:

Number: **201436037**

Release Date: 9/5/2014

Index Number: 167.22-01

Third Party Communication: None

Date of Communication: Not Applicable

Person To Contact: [Redacted Text]

[Redacted Text], ID No.

Telephone Number: [Redacted Text]

Refer Reply To:

CC:PSI:B06

PLR-148310-13

Date:

May 22, 2014

LEGEND:

Taxpayer =

Parent =

State A =

State B =

State C =

Commission A =

Commission B =

Commission C =

Year A =

Year B =

Date A =

Date B =

Date C =

Case =

Director =

Dear [Redacted Text]:

This letter responds to the request, dated November 25, 2013, of Taxpayer for a ruling on the application of the normalization rules of the Internal Revenue Code to certain accounting and regulatory procedures, described below.

The representations set out in your letter follow.

Taxpayer is a regulated public utility incorporated in State A and State B. It is wholly owned by Parent. Taxpayer is engaged in the transmission, distribution, and supply of electricity in State A and State C. Taxpayer is subject to the regulatory jurisdiction of Commission A, Commission B, and Commission C with respect to terms and conditions of service and particularly the rates it may charge for the provision of service. Taxpayer's rates are established on a rate of return basis. Taxpayer takes accelerated depreciation, including "bonus depreciation" where available and, for each year beginning in Year A and ending in Year B, Taxpayer individually (as well as the consolidated return filed by Parent) has or expects to, produce a net operating loss (NOL). On its regulatory books of account, Taxpayer "normalizes" the differences between regulatory depreciation and tax depreciation. This means that, where accelerated depreciation reduces taxable income, the taxes that a taxpayer would have paid if regulatory depreciation (instead of accelerated tax depreciation) were claimed constitute "cost-free capital" to the taxpayer. A taxpayer that normalizes these differences, like Taxpayer, maintains a reserve account showing the amount of tax liability that is deferred as a result of the accelerated depreciation. This reserve is the accumulated deferred income tax (ADIT) account. Taxpayer maintains an ADIT account. In addition, Taxpayer maintains an offsetting series of entries - a "deferred tax asset" and a "deferred tax expense" - that reflect that portion of those `tax losses' which, while due to accelerated depreciation, did not actually defer tax because of the existence of an net operating loss carryover (NOLC). Taxpayer, for normalization purposes, calculates the portion of the NOLC attributable to accelerated depreciation using a "with or without" methodology, meaning that an NOLC is attributable to accelerated depreciation to the extent of the lesser of the accelerated depreciation or the NOLC.

Taxpayer filed a general rate case with Commission B on Date A (Case). The test year used in the Case was the 12 month period ending on Date B. In computing its income tax expense element of cost of service, the tax benefits attributable to accelerated depreciation were normalized in accordance with Commission B policy and were not flowed thru to ratepayers. The data originally filed in Case included six months of forecast data, which the Taxpayer updated with actual data in the course of proceedings. In establishing the rate base on which Taxpayer was to be allowed to earn a return Commission B offset rate base by Taxpayer's ADIT balance, using a 13-month average of the month-end balances of the relevant accounts. Taxpayer argued that the ADIT balance should be reduced by the amounts that Taxpayer calculates did not actually defer tax due to the presence of the NOLC, as represented in the deferred tax asset account. Testimony by various other participants in Case argued against Taxpayer's proposed calculation of ADIT. One proposal made to Commission B was, if Commission B allowed Taxpayer to reduce the ADIT balance as Taxpayer proposed, then Taxpayer's income tax expense element of service should be reduced by that same amount.

Commission B, in an order issued on Date C, allowed Taxpayer to reduce ADIT by the amount that Taxpayer calculates did not actually defer tax due to the presence of the NOLC and ordered Taxpayer to seek a ruling on the effects of an NOLC on ADIT. Rates went into effect on Date C.

Taxpayer proposed, and Commission B accepted, that it be permitted to annualize, rather than average, its reliability plant additions and to extend the period of anticipated reliability plant additions to be included in rate base for an additional quarter. Taxpayer also proposed, and Commission B accepted, that no additional ADIT be reflected as a result of these adjustments inasmuch as any additional book and tax depreciation produced by considering these assets would simply increase Taxpayer's NOLC and thus there would be no net impact on ADIT.

Taxpayer requests that we rule as follows:

1. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balances offset by a portion of its NOLC-related account balance that is less than the amount attributable to accelerated depreciation computed on a "with or without" basis would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

2. The imputation of incremental ADIT on account of the reliability plant addition adjustments described above would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.

3. Under the circumstances described above, any reduction in Taxpayer's tax expense element of cost of service to reflect the tax benefit of its NOLC would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.

Law and Analysis

Section 168(f)(2) of the Code provides that the depreciation deduction determined under section 168 shall not apply to any public utility property (within the meaning of section 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, section 168(i)(9)(A)(i) of the Code requires the taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under section 168(i)(9)(A)(ii), if the amount allowable as a deduction under section 168 differs from the amount that-would be allowable as a deduction under section 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under section 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) of the Code provides that one way the requirements of section 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under section 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under section 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base.

Former section 167(l) of the Code generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former section 167(l)(3)(G) in a manner consistent with that found in section 168(i)(9)(A). Section 1.167(1)-1(a)(1) of the Income Tax Regulations provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under section 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 1.167(l)-1(h)(1)(i) provides that the reserve established for public utility property should reflect the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes.

Section 1.167(1)-1(h)(1)(iii) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the amount of the actual tax liability. This amount shall be taken into account for the taxable year in which the different methods of depreciation are used. If, however, in respect of any taxable year the use of a method of depreciation other than a subsection (1) method for purposes of determining the taxpayer's reasonable allowance under section 167(a) results in a net operating loss carryover to a year succeeding such taxable year which would not have arisen (or an increase in such carryover which would not have arisen) had the taxpayer determined his reasonable allowance under section 167(a) using a subsection (1) method, then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director.

Section 1.167(1)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. This regulation further provides that, with respect to any account, the aggregate amount allocable to deferred tax under section 167(1) shall not be reduced except to reflect the amount for any taxable year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation. That section also notes that the aggregate amount allocable to deferred taxes may be reduced to reflect the amount for any taxable year by which federal income taxes are greater by reason of the prior use of different methods of depreciation under section 1.167(1)-1(h)(1)(i) or to reflect asset retirements or the expiration of the period for depreciation used for determining the allowance for depreciation under section 167(a).

Section 1.167(1)-(h)(6)(i) provides that, notwithstanding the provisions of subparagraph (1) of that paragraph, a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking.

Section 1.167(1)-(h)(6)(ii) provides that, for the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under subdivision (i), above, if solely an historical period is used to determine depreciation for Federal income tax expense for ratemaking purposes, then the amount of the reserve account for that period is the amount of the reserve (determined under section 1.167(1)-1(h)(2)(i)) at the end of the historical period. If such determination is made by reference both to an historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period.

Section 1.167(l)-1(h) requires that a utility must maintain a reserve reflecting the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes. Taxpayer has done so. Section 1.167(1)-(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Section 56(a)(1)(D) provides that, with respect to public utility property the Secretary shall prescribe the requirements of a normalization method of accounting for that section.

In Case, Commission B has reduced rate base by Taxpayer's ADIT account, as modified by the account which Taxpayer has designed to calculate the effects of the NOLC. Section 1.167(1)-1(h)(1)(iii) makes clear that the effects of an NOLC must be taken into account for normalization purposes. Further, while that section provides no specific mandate on methods, it does provide that the Service has discretion to determine whether a particular method satisfies the normalization requirements. Section 1.167(1)-(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Because the ADIT account, the reserve account for deferred taxes, reduces rate base, it is clear that the portion of an NOLC that is attributable to accelerated depreciation must be taken into account in calculating the amount of the reserve for deferred taxes (ADIT). Thus, the order by Commission B is in accord with the normalization requirements. The "with or without" methodology employed by Taxpayer is specifically designed to ensure that the portion of the NOLC attributable to accelerated depreciation is correctly taken into account by maximizing the amount of the NOLC attributable to accelerated depreciation. This methodology provides certainty and prevents the possibility of "flow through" of the benefits of accelerated depreciation to ratepayers. Under these facts, any method other than the "with and without" method would not provide the same level of certainty and therefore the use of any other methodology is inconsistent with the normalization rules.

Regarding the second issue, § 1.167(1)-(h)(6)(i) provides, as noted above, that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Increasing Taxpayer's ADIT account by an amount representing those taxes that would have been deferred absent the NOLC increases the ADIT reserve account (which will then reduce rate base) beyond the permissible amount.

Regarding the third issue, reduction of Taxpayer's tax expense element of cost of service, we believe that such reduction would, in effect, flow through the tax benefits of accelerated depreciation deductions through to rate payers even though the Taxpayer has not yet realized such benefits. This would violate the normalization provisions.

We rule as follows:

1. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balances offset by a portion of its NOLC-related account balance that is less than the amount attributable to accelerated depreciation computed on a "with or without" basis would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

2. The imputation of incremental ADIT on account of the reliability plant addition adjustments described above would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.

3. Under the circumstances described above, any reduction in Taxpayer's tax expense element of cost of service to reflect the tax benefit of its NOLC would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.

This ruling is based on the representations submitted by Taxpayer and is only valid if those representations are accurate. The accuracy of these representations is subject to verification on audit.

Except as specifically determined above, no opinion is expressed or implied concerning the Federal income tax consequences of the matters described above.

This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent. In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative. W e are also sending a copy of this letter ruling to the Director.

Sincerely,

Peter C. Friedman

Senior Technician Reviewer, Branch 6

(Passthroughs & Special Industries)

cc: [Redacted Text]

Private Letter Rulings

Private Letter Ruling 201436038, 09/05/14, IRC Sec(s). 167

UIL No. 167.22-01

Accelerated depreciation-accumulated deferred income tax-net operating loss carryover-computation based on "with or without" basis-normalization-limitations on reasonable allowance in case of property of public utilities.

Headnote:

Reduction of taxpayer/regulated electric utility's rate base by full amount of its ADIT account balances offset by portion of its NOLC-related account that is less than amount attributable to accelerated depreciation computed on "with or without" basis would be inconsistent with **Code Sec. 168(i)(9)**; and **Reg § 1.167(l)-1** requirements.

Reference(s): **Code Sec. 167; Code Sec. 168;**

Full Text:

Number: **201436038**

Release Date: 9/5/2014

Index Number: 167.22-01

Third Party Communication: None

Date of Communication: Not Applicable

Person To Contact: [Redacted Text]

[Redacted Text], ID No.

Telephone Number: [Redacted Text]

Refer Reply To:

CC:PSI:B06

PLR-148311-13

Date:

May 22, 2014

LEGEND:

Taxpayer =

Parent =

State A =

State B =

State C =

Commission A =

Commission B =

Commission C =

Year A =

Year B =

Date A =

Date B =

Date C =

Date D =

Date E =

Case =

Director =

Dear .[Redacted Text]:

This letter responds to the request, dated November 25, 2013, of Taxpayer for a ruling on the application of the normalization rules of the Internal Revenue Code to certain accounting and regulatory procedures, described below.

The representations set out in your letter follow.

Taxpayer is a regulated public utility incorporated in State A and State B. It is wholly owned, through a limited liability company, by Parent. Taxpayer is engaged in the transmission, distribution, and supply of electricity in State A and State C. Taxpayer also provides natural gas and natural gas transmission services in State A. Taxpayer is subject to the regulatory jurisdiction of Commission A, Commission B, and Commission C with respect to terms and conditions of service and particularly the rates it may charge for the provision of service. Taxpayer's rates are established on a rate of return basis. Taxpayer takes accelerated depreciation, including "bonus depreciation" where available and, for each year beginning in Year A and ending in Year B, Taxpayer individually (as well as the consolidated return filed by Parent) has or expects to, produce a net operating loss (NOL). On its regulatory books of account, Taxpayer "normalizes" the differences between regulatory depreciation and tax depreciation. This means that, where accelerated depreciation reduces taxable income, the taxes that a taxpayer would have paid if regulatory depreciation (instead of accelerated tax depreciation) were claimed constitute "cost-free capital" to the taxpayer. A taxpayer that normalizes these differences, like Taxpayer, maintains a reserve account showing the amount of tax liability that is deferred as a result of the accelerated depreciation. This reserve is the accumulated deferred income tax (ADIT) account. Taxpayer maintains an ADIT account. In addition, Taxpayer maintains an offsetting series of entries - a "deferred tax asset" and a "deferred tax expense" - that reflect that portion of those 'tax losses' which, while due to accelerated depreciation, did not actually defer tax because of the existence of an net operating loss carryover (NOLC). Taxpayer, for normalization purposes, calculates the portion of the NOLC attributable to accelerated depreciation using a "with or without" methodology, meaning that an NOLC is attributable to accelerated depreciation to the extent of the lesser of the accelerated depreciation or the NOLC.

Taxpayer filed a general rate case with Commission B on Date A (Case). The test year used in the Case was the 12 month period ending on Date B. In computing its income tax expense element of cost of service, the tax benefits attributable to accelerated depreciation were normalized in accordance with

Commission B policy and were not flowed thru to ratepayers. The data originally filed in Case was updated in the course of proceedings. In establishing the rate base on which Taxpayer was to be allowed to earn a return Commission B offset rate base by Taxpayer's ADIT balance, using a 13-month average of the month-end balances of the relevant accounts. Taxpayer argued that the ADIT balance should be reduced by the amounts that Taxpayer calculates did not actually defer tax due to the presence of the NOLC, as represented in the deferred tax asset account. Testimony by various other participants in Case argued against Taxpayer's proposed calculation of ADIT.

On Date C, a settlement agreement was filed with Commission B, incorporating the Taxpayer's proposed treatment of the tax consequences of its NOLC. In an order issued on Date D, Commission B issued an order approving the settlement agreement and also ordered Taxpayer to seek a ruling on the effects of an NOLC on ADIT. Rates went into effect on Date E.

Taxpayer proposed, and Commission B accepted, that it be permitted to annualize, rather than average, its reliability plant additions and to extend the period of anticipated reliability plant additions to be included in rate base for an additional eight months. Taxpayer also proposed, and Commission B accepted, that no additional ADIT be reflected as a result of these adjustments inasmuch as any additional book and tax depreciation produced by considering these assets would simply increase Taxpayer's NOLC and thus there would be no net impact on ADIT.

Taxpayer requests that we rule as follows:

1. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balances offset by a portion of its NOLC-related account balance that is less than the amount attributable to accelerated depreciation computed on a "with or without" basis would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

2. The imputation of incremental ADIT on account of the reliability plant addition adjustments described above would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.

Law and Analysis

Section 168(f)(2) of the Code provides that the depreciation deduction determined under section 168 shall not apply to any public utility property (within the meaning of section 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, section 168(i)(9)(A)(i) of the Code requires the taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under section 168(l)(9)(A)(ii), if the amount allowable as a deduction under section 168 differs from the amount that-would be allowable as a deduction under section 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under section 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) of the Code provides that one way the requirements of section 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under section 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under section 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base.

Former section 167(l) of the Code generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former section 167(l)(3)(G) in a manner consistent with that found in section 168(i)(9)(A). Section 1.167(1)-1(a)(1) of the Income Tax Regulations provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under section 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 1.167(l)-1(h)(1)(i) provides that the reserve established for public utility property should reflect the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes.

Section 1.167(1)-1(h)(1)(iii) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the amount of the actual tax liability. This amount shall be taken into account for the taxable year in which the different methods of depreciation are used. If, however, in respect of any taxable year the use of a method of depreciation other than a subsection (1) method for purposes of determining the taxpayer's reasonable allowance under section 167(a) results in a net operating loss carryover to a year succeeding such taxable year which would not have arisen (or an increase in such carryover which would not have arisen) had the taxpayer determined his reasonable allowance under section 167(a) using a subsection (1) method, then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director.

Section 1.167(1)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. This regulation further provides that, with respect to any account, the aggregate amount allocable to deferred tax under section 167(1) shall not be reduced except to reflect the amount for any taxable year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation. That section also notes that the aggregate amount allocable to deferred taxes may be reduced to reflect the amount for any taxable year by which federal income taxes are greater by reason of the prior use of different methods of depreciation under section 1.167(1)-1(h)(1)(i) or to reflect asset retirements or the expiration of the period for depreciation used for determining the allowance for depreciation under section 167(a).

Section 1.167(1)-(h)(6)(i) provides that, notwithstanding the provisions of subparagraph (1) of that paragraph, a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking.

Section 1.167(1)-(h)(6)(ii) provides that, for the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under subdivision (i), above, if solely an historical period is used to determine depreciation for Federal income tax expense for ratemaking purposes, then the amount of the reserve account for that period is the amount of the reserve (determined under section 1.167(1)-1(h)(2)(i)) at the end of the historical period. If such determination is made by reference both to an historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period.

Section 1.167(l)-1(h) requires that a utility must maintain a reserve reflecting the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes. Taxpayer has done so. Section 1.167(1)-(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Section 56(a)(1)(D) provides that, with respect to public utility property the Secretary shall prescribe the requirements of a normalization method of accounting for that section.

In Case, Commission B has reduced rate base by Taxpayer's ADIT account, as modified by the account which Taxpayer has designed to calculate the effects of the NOLC. Section 1.167(1)-1(h)(1)(iii) makes clear that the effects of an NOLC must be taken into account for normalization purposes. Further, while that section provides no specific mandate on methods, it does provide that the Service has discretion to determine whether a particular method satisfies the normalization requirements. Section 1.167(1)-(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Because the ADIT account, the reserve account for deferred taxes, reduces rate base, it is clear that the portion of an NOLC that is attributable to accelerated depreciation must be taken into account in calculating the amount of the reserve for deferred taxes (ADIT). Thus, the order by Commission B is in accord with the normalization requirements. The "with or without" methodology employed by Taxpayer is specifically designed to ensure that the portion of the NOLC attributable to accelerated depreciation is correctly taken into account by maximizing the amount of the NOLC attributable to accelerated depreciation. This methodology provides certainty and prevents the possibility of "flow through" of the benefits of accelerated depreciation to ratepayers. Under these facts, any method other than the "with and without" method would not provide the same level of certainty and therefore the use of any other methodology is inconsistent with the normalization rules.

Regarding the second issue, § 1.167(1)-(h)(6)(i) provides, as noted above, that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Increasing Taxpayer's ADIT account by an amount representing those taxes that would have been deferred absent the NOLC increases the ADIT reserve account (which will then reduce rate base) beyond the permissible amount.

We rule as follows:

1. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balances offset by a portion of its NOLC-related account balance that is less than the amount attributable to accelerated depreciation computed on a "with or without" basis would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

2. The imputation of incremental ADIT on account of the reliability plant addition adjustments described above would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.

This ruling is based on the representations submitted by Taxpayer and is only valid if those representations are accurate. The accuracy of these representations is subject to verification on audit.

Except as specifically determined above, no opinion is expressed or implied concerning the Federal income tax consequences of the matters described above.

This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent. In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative. We are also sending a copy of this letter ruling to the Director.

Sincerely,

Peter C. Friedman

Senior Technician Reviewer, Branch 6

(Passthroughs & Special Industries)

cc: [Redacted Text]

Private Letter Rulings

Private Letter Ruling 201438003, 09/19/2014, IRC Sec(s). 168

UIL No. 167.22-01

Accelerated depreciation-accumulated deferred income tax-net operating loss carryover-normalization-limitations on reasonable allowance in case of property of public utilities.

Headnote:

Reduction of taxpayer/regulated electric utility's rate base by full amount of its ADIT account balance unreduced by balance of NOLC-related account balance would be inconsistent with **Code Sec. 168(i)(9)**; and **Reg § 1.167(l)-1** requirements.

Reference(s): **Code Sec. 168; Code Sec. 167;**

Full Text:

Number: **201438003**

Release Date: 9/19/2014

Index Number: 167.22-01

Third Party Communication: None

Date of Communication: Not Applicable

Person To Contact: [Redacted Text]

[Redacted Text], ID No.

Telephone Number: [Redacted Text]

Refer Reply To:

CC:PSI:B06

PLR-104157-14

Date:

June 12, 2014

LEGEND:

Taxpayer =

Parent =

State A =

Commission A =

Commission B =

Year A =

Year B =

Year C =

Year D =

Date A =

Date B =

Date C =

Date D =

Case =

Director =

Dear [Redacted Text]:

This letter responds to the request, dated January 24, 2014, and additional submission dated May 19, 2014, submitted on behalf of Taxpayer for a ruling on the application of the normalization rules of the Internal Revenue Code to certain accounting and regulatory procedures, described below.

The representations set out in your letter follow.

Taxpayer is a regulated, investor-owned public utility incorporated under the laws of State A primarily engaged in the business of supplying electricity in State A. Taxpayer is subject to the regulatory jurisdiction of Commission A and Commission B with respect to terms and conditions of service and particularly the rates it may charge for the provision of service. Taxpayer's rates are established on a rate of return basis.

Taxpayer is wholly owned by Parent, and Taxpayer is included in a consolidated federal income tax return of which Parent is the common parent. Taxpayer employs the accrual method of accounting and reports on a calendar year basis.

Taxpayer filed a rate case application on Date A (Case). In its filing, Taxpayer used as its starting point actual data from the historic test period, calendar Year A. It then projected data for Year B through Year C. Taxpayer updated, amended, and supplemented its data several times during the course of the proceedings. Rates in this proceeding were intended to, and did, go into effect for the period Date B through Date C.

In computing its income tax expense element of cost of service, the tax benefits attributable to accelerated depreciation were normalized and were not flowed thru to ratepayers.

In its rate case filing, Taxpayer anticipated that it would claim accelerated depreciation, including "bonus depreciation" on its tax returns to the extent that such depreciation was available in all years for which data was provided. Additionally, Taxpayer forecasted that it would incur a net operating loss (NOL) in Year D. Taxpayer anticipated that it had the capacity to carry back a portion of this NOL with the remainder producing a net operating loss carryover (NOLC) as of the end of Year D.

On its regulatory books of account, Taxpayer "normalizes" the differences between regulatory depreciation and tax depreciation. This means that, where accelerated depreciation reduces taxable income, the taxes that a taxpayer would have paid if regulatory depreciation (instead of accelerated tax depreciation) were claimed constitute "cost-free capital" to the taxpayer. A taxpayer that normalizes these differences, like Taxpayer, maintains a reserve account showing the amount of tax liability that is deferred as a result of the accelerated depreciation. This reserve is the accumulated deferred income tax (ADIT) account. Taxpayer maintains an ADIT account. In addition, Taxpayer maintains an offsetting series of entries - a "deferred tax asset" and a "deferred tax expense" - that reflect that portion of those 'tax losses' which, while due to accelerated depreciation, did not actually defer tax because of the existence of an NOLC.

In the setting of utility rates in State, a utility's rate base is offset by its ADIT balance. In its rate case filing and throughout the proceeding, Taxpayer maintained that the ADIT balance should be reduced by the amounts that Taxpayer calculates did not actually defer tax due to the presence of the NOLC, as represented in the deferred tax asset account. Thus, Taxpayer argued that the rate base should be reduced as of the end of Year D by its federal ADIT balance net of the deferred tax asset account attributable to the federal NOLC. It based this position on its determination that this net amount represented the true measure of federal income taxes deferred on account of its claiming accelerated tax depreciation deductions and, consequently, the actual quantity of "cost-free" capital available to it. It also asserted that the failure to reduce its rate base offset by the deferred tax asset attributable to the federal NOLC would be inconsistent with the normalization rules Testimony by another participant in Case argued against Taxpayer's proposed calculation of ADIT.

Commission A, in an order issued on Date D, held that it is inappropriate to include the NOL in rate base for ratemaking purposes. Commission A further stated that it is the intent of the Commission that Taxpayer comply with the normalization method of accounting and tax normalization regulations. Commission noted that if Taxpayer later obtains a ruling from the IRS which affirms Taxpayer's position, Taxpayer may file seeking an adjustment. Commission A also held that to the extent tax normalization rules require recording the NOL to rate base in the specified years, no rate of return is authorized.

Taxpayer requests that we rule as follows:

1. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balance unreduced by the balance of its NOLC-related account balance would be inconsistent with (and, hence, violative of) the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

2. For purposes of Ruling 1 above, the use of a balance of Taxpayer's NOLC-related account balance that is less than the amount attributable to accelerated depreciation computed on a "with and without" basis would be inconsistent with (and, hence, violative of) the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

3. Under the circumstances described above, the assignment of a zero rate of return to the balance of Taxpayer's NOLC-related account balance would be inconsistent with (and, hence, violative of) the requirements of § 168(i)(9) and § 1.167(l)-1.

Law and Analysis

Section 168(f)(2) of the Code provides that the depreciation deduction determined under section 168 shall not apply to any public utility property (within the meaning of section 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, section 168(i)(9)(A)(i) of the Code requires the taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under section 168(i)(9)(A)(ii), if the amount allowable as a deduction under section 168 differs from the amount that would be allowable as a deduction under section 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under section 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) of the Code provides that one way the requirements of section 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under section 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under section 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base.

Former section 167(l) of the Code generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former section 167(l)(3)(G) in a manner consistent with that found in section 168(i)(9)(A). Section 1.167(l)-1(a)(1) of the Income Tax Regulations provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under section 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 1.167(l)-1(h)(1)(i) provides that the reserve established for public utility property should reflect the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes.

Section 1.167(l)-1(h)(1)(iii) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the amount of the actual tax liability. This amount shall be taken into account for the taxable year in which the different methods of depreciation are used. If, however, in respect of any taxable year the use of a method of depreciation other than a subsection (1) method for purposes of determining the taxpayer's reasonable allowance under section 167(a) results in a net operating loss carryover to a year succeeding such taxable year which would not have arisen (or an increase in such carryover which would not have arisen) had the taxpayer determined his reasonable allowance under section 167(a) using a subsection (1) method, then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director.

Section 1.167(l)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. This regulation further provides that, with respect to any account, the aggregate amount allocable to deferred tax under section 167(1) shall not be reduced except to reflect the amount for any taxable year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation. That section also notes that the aggregate amount allocable to deferred taxes may be reduced to reflect the amount for any taxable year by which federal income taxes are greater by reason of the prior use of different methods of depreciation under section 1.167(l)-1(h)(1)(i) or to reflect asset retirements or the expiration of the period for depreciation used for determining the allowance for depreciation under section 167(a).

Section 1.167(l)-1(h)(6)(i) provides that, notwithstanding the provisions of subparagraph (1) of that paragraph, a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking.

Section 1.167(l)-1(h)(6)(ii) provides that, for the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under subdivision (i), above, if solely an historical period is used to determine depreciation for Federal income tax expense for ratemaking purposes, then the amount of the reserve account for that period is the amount of the reserve (determined under section 1.167(l)-1(h)(2)(i)) at the end of the historical period. If such determination is made by reference both to an historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period.

Section 1.167(l)-1(h) requires that a utility must maintain a reserve reflecting the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes. Taxpayer has done so. Section 1.167(l)-1(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Section 56(a)(1)(D) provides that, with respect to public utility property the Secretary shall prescribe the requirements of a normalization method of accounting for that section.

Regarding the first issue, § 1.167(l)-1(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Because the ADIT account, the reserve account for deferred taxes, reduces rate base, it is clear that the portion of an NOLC that is attributable to accelerated depreciation must be taken into account in calculating the amount of the reserve for deferred taxes (ADIT). Thus, the order by Commission A is not in accord with the normalization requirements.

Regarding the second issue, § 1.167(l)-1(h)(1)(iii) makes clear that the effects of an NOLC must be taken into account for normalization purposes. Section 1.167(l)-1(h)(1)(iii) provides generally that, if, in respect of any year, the use of other than regulatory depreciation for tax purposes results in an NOLC carryover (or an increase in an NOLC which would not have arisen had the taxpayer claimed only regulatory depreciation for tax purposes), then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director. While that section provides no specific mandate on methods, it does provide that the Service has discretion to determine whether a particular method satisfies the normalization requirements. The "with or without" methodology employed by Taxpayer is specifically designed to ensure that the portion of the NOLC attributable to accelerated depreciation is correctly taken into account by maximizing the amount of the NOLC attributable to accelerated depreciation. This methodology provides certainty and prevents the possibility of "flow through" of the benefits of accelerated depreciation to ratepayers. Under these facts, any method other than the "with and without" method would not provide the same level of certainty and therefore the use of any other methodology is inconsistent with the normalization rules.

Regarding the third issue, assignment of a zero rate of return to the balance of Taxpayer's NOLC-related account balance would, in effect, flow the tax benefits of accelerated depreciation deductions through to rate payers. This would violate the normalization provisions.

We rule as follows:

1. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balance unreduced by the balance of its NOLC-related account balance would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

2. For purposes of Ruling 1 above, the use of a balance of Taxpayer's NOLC-related account balance that is less than the amount attributable to accelerated depreciation computed on a "with and without" basis would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

3. Under the circumstances described above, the assignment of a zero rate of return to the balance of Taxpayer's NOLC-related account balance would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.

This ruling is based on the representations submitted by Taxpayer and is only valid if those representations are accurate. The accuracy of these representations is subject to verification on audit.

Except as specifically determined above, no opinion is expressed or implied concerning the Federal income tax consequences of the matters described above.

This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent. In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative. W e are also sending a copy of this letter ruling to the Director.

Sincerely,

Peter C. Friedman

Senior Technician Reviewer, Branch 6

(Passthroughs & Special Industries)

cc: [Redacted Text]

Private Letter Rulings

Private Letter Ruling 201519021, 05/08/2015, IRC Sec(s). 168

UIL No. 167.22-01

Accelerated depreciation-accumulated deferred income tax-net operating loss carryover-normalization-limitations on reasonable allowance in case of property of public utilities.

Headnote:

Reduction of taxpayer/investor-owned public utility's rate base by full amount of its ADIT account balance unreduced by balance of NOLC-related account balance would be inconsistent with **Code Sec. 168(i)(9)**; and **Reg § 1.167(l)-1** requirements.

Reference(s): **Code Sec. 168; Code Sec. 167;**

Full Text:

Number: **201519021**

Release Date: 5/8/2015

Index Number: 167.22-01

Third Party Communication: None

Date of Communication: Not Applicable

Person To Contact: [Redacted Text]

[Redacted Text], ID No.

Telephone Number: [Redacted Text]

Refer Reply To:

CC:PSI:B06

PLR-136851-14

Date:

February 04, 2015

LEGEND:

Taxpayer =

Parent =

State A =

Commission =

Year A =

Year B =

Year C =

Year D =

Date A =

Date B =

Date C =

Date D =

Case =

Director =

Dear [Redacted Text]:

This letter responds to the request, dated October 1, 2014, submitted on behalf of Taxpayer for a ruling on the application of the normalization rules of the Internal Revenue Code to certain accounting and regulatory procedures, described below.

The representations set out in your letter follow.

Taxpayer is a regulated, investor-owned public utility incorporated under the laws of State A primarily engaged in the business of supplying natural gas service in State A. Taxpayer is subject to the regulatory jurisdiction of Commission with respect to terms and conditions of service and as to the rates it may charge for the provision of service. Taxpayer's rates are established on a cost of service basis.

Taxpayer is wholly owned by Parent, and Taxpayer is included in a consolidated federal income tax return of which Parent is the common parent. Taxpayer employs the accrual method of accounting and reports on a calendar year basis.

Taxpayer filed a rate case application on Date A (Case). In its filing, Taxpayer used as its starting point actual data from the historic test period, calendar Year A. It then projected data for Year B through Year D. Taxpayer updated, amended, and supplemented its data several times during the course of the proceedings. Rates in this proceeding were intended to, and did, go into effect for the period Date B through Date C.

In computing its income tax expense element of cost of service, the tax benefits attributable to accelerated depreciation were normalized and were not flowed thru to ratepayers.

In its rate case filing, Taxpayer anticipated that it would claim accelerated depreciation, including "bonus depreciation" on its tax returns to the extent that such depreciation was available in all years for which data was provided. Additionally, Taxpayer forecasted that it would incur a net operating loss (NOL) in each of Year B, Year C, and Year D. Taxpayer anticipated that it had the capacity to carry back a portion of this NOL with the remainder producing a net operating loss carryover (NOLC) as of the end of Year C and Year D, the beginning and end of the test period.

On its regulatory books of account, Taxpayer "normalizes" the differences between regulatory depreciation and tax depreciation. This means that, where accelerated depreciation reduces taxable income, the taxes that a taxpayer would have paid if regulatory depreciation (instead of accelerated tax depreciation) were claimed constitute "cost-free capital" to the taxpayer. A taxpayer that normalizes these differences, like Taxpayer, maintains a reserve account showing the amount of tax liability that is deferred as a result of the accelerated depreciation. This reserve is the accumulated deferred income tax (ADIT) account. Taxpayer maintains an ADIT account. In addition, Taxpayer maintains an offsetting series of entries - a "deferred tax asset" and a "deferred tax expense" - that reflect that portion of those `tax losses' which, while due to accelerated depreciation, did not actually defer tax because of the existence of an NOLC.

In the setting of utility rates in State, a utility's rate base is offset by its ADIT balance. In its rate case filing and throughout the proceeding, Taxpayer maintained that the ADIT balance should be reduced by the amounts that Taxpayer calculates did not actually defer tax due to the presence of the NOLC, as represented in the deferred tax asset account. Thus, Taxpayer argued that the rate base should be reduced as of the end of Year D by its federal ADIT balance net of the deferred tax asset account attributable to the federal NOLC. It based this position on its determination that this net amount represented the true measure of federal income taxes deferred on account of its claiming accelerated tax depreciation deductions and, consequently, the actual quantity of "cost-free" capital available to it. It also asserted that the failure to reduce its rate base offset by the deferred tax asset attributable to the federal NOLC would be inconsistent with the normalization rules Testimony by another participant in Case argued against Taxpayer's proposed calculation of ADIT.

Commission, in an order issued on Date D, held that it is inappropriate to include the NOL in rate base for ratemaking purposes. Commission further stated that it is the intent of the Commission that Taxpayer comply with the normalization method of accounting and tax normalization regulations. Commission noted that if Taxpayer later obtains a ruling from the IRS which affirms Taxpayer's position, Taxpayer may file seeking an adjustment. Commission also held that to the extent tax normalization rules require including the NOL in rate base in the specified years, no rate of return is authorized.

Taxpayer requests that we rule as follows:

1. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balance unreduced by the balance of its NOLC-related account balance would be inconsistent with (and, hence, violative of) the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

2. For purposes of Ruling 1 above, the use of a balance of Taxpayer's NOLC-related account balance that is less than the amount attributable to accelerated depreciation computed on a "with and without" basis would be inconsistent with (and, hence, violative of) the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

3. Under the circumstances described above, the assignment of a zero rate of return to the balance of Taxpayer's NOLC-related account balance would be inconsistent with (and, hence, violative of) the requirements of § 168(i)(9) and § 1.167(l)-1.

Law and Analysis

Section 168(f)(2) of the Code provides that the depreciation deduction determined under section 168 shall not apply to any public utility property (within the meaning of section 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, section 168(i)(9)(A)(i) of the Code requires the taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under section 168(i)(9)(A)(ii), if the amount allowable as a deduction under section 168 differs from the amount that-would be allowable as a deduction under section 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under section 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) of the Code provides that one way the requirements of section 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under section 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under section 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base.

Former section 167(l) of the Code generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former section 167(l)(3)(G) in a manner consistent with that found in section 168(i)(9)(A). Section 1.167(l)-1(a)(1) of the Income Tax Regulations provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under section 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 1.167(l)-1(h)(1)(i) provides that the reserve established for public utility property should reflect the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes.

Section 1.167(l)-1(h)(1)(iii) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the amount of the actual tax liability. This amount shall be taken into account for the taxable year in which the different methods of depreciation are used. If, however, in respect of any taxable year the use of a method of depreciation other than a subsection (1) method for purposes of determining the taxpayer's reasonable allowance under section 167(a) results in a net operating loss carryover to a year succeeding such taxable year which would not have arisen (or an increase in such carryover which would not have arisen) had the taxpayer determined his reasonable allowance under section 167(a) using a subsection (1) method, then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director.

Section 1.167(l)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. This regulation further provides that, with respect to any account, the aggregate amount allocable to deferred tax under section 167(1) shall not be reduced except to reflect the amount for any taxable year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation. That section also notes that the aggregate amount allocable to deferred taxes may be reduced to reflect the amount for any taxable year by which federal income taxes are greater by reason of the prior use of different methods of depreciation under section 1.167(l)-1(h)(1)(i) or to reflect asset retirements or the expiration of the period for depreciation used for determining the allowance for depreciation under section 167(a).

Section 1.167(l)-1(h)(6)(i) provides that, notwithstanding the provisions of subparagraph (1) of that paragraph, a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking.

Section 1.167(l)-1(h)(6)(ii) provides that, for the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under subdivision (i), above, if solely an historical period is used to determine depreciation for Federal income tax expense for ratemaking purposes, then the amount of the reserve account for that period is the amount of the reserve (determined under section 1.167(l)-1(h)(2)(i)) at the end of the historical period. If such determination is made by reference both to an historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period.

Section 1.167(l)-1(h) requires that a utility must maintain a reserve reflecting the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes. Taxpayer has done so. Section 1.167(l)-1(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Section 56(a)(1)(D) provides that, with respect to public utility property the Secretary shall prescribe the requirements of a normalization method of accounting for that section.

Regarding the first issue, § 1.167(l)-1(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Because the ADIT account, the reserve account for deferred taxes, reduces rate base, it is clear that the portion of an NOLC that is attributable to accelerated depreciation must be taken into account in calculating the amount of the reserve for deferred taxes (ADIT). Thus, the order by Commission is not in accord with the normalization requirements.

Regarding the second issue, § 1.167(l)-1(h)(1)(iii) makes clear that the effects of an NOLC must be taken into account for normalization purposes. Section 1.167(l)-1(h)(1)(iii) provides generally that, if, in respect of any year, the use of other than regulatory depreciation for tax purposes results in an NOLC carryover (or an increase in an NOLC which would not have arisen had the taxpayer claimed only regulatory depreciation for tax purposes), then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director. While that section provides no specific mandate on methods, it does provide that the Service has discretion to determine whether a particular method satisfies the normalization requirements. The "with or without" methodology employed by Taxpayer is specifically designed to ensure that the portion of the NOLC attributable to accelerated depreciation is correctly taken into account by maximizing the amount of the NOLC attributable to accelerated depreciation. This methodology provides certainty and prevents the possibility of "flow through" of the benefits of accelerated depreciation to ratepayers. Under these specific facts, any method other than the "with and without" method would not provide the same level of certainty and therefore the use of any other methodology is inconsistent with the normalization rules.

Regarding the third issue, assignment of a zero rate of return to the balance of Taxpayer's NOLC-related account balance would, in effect, flow the tax benefits of accelerated depreciation deductions through to rate payers. This would violate the normalization provisions.

We rule as follows:

1. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balance unreduced by the balance of its NOLC-related account balance would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

2. For purposes of Ruling 1 above, the use of a balance of Taxpayer's NOLC-related account balance that is less than the amount attributable to accelerated depreciation computed on a "with and without" basis would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

3. Under the circumstances described above, the assignment of a zero rate of return to the balance of Taxpayer's NOLC-related account balance would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.

This ruling is based on the representations submitted by Taxpayer and is only valid if those representations are accurate. The accuracy of these representations is subject to verification on audit.

Except as specifically determined above, no opinion is expressed or implied concerning the Federal income tax consequences of the matters described above.

This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent. In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative. W e are also sending a copy of this letter ruling to the Director.

Sincerely,

Peter C. Friedman

Senior Technician Reviewer, Branch 6

Office of the Associate Chief Counsel

(Passthroughs & Special Industries)

Private Letter Rulings

Private Letter Ruling 201534001, 08/21/2015, IRC Sec(s). 168

UIL No. 167.22-01

Accelerated depreciation-accumulated deferred income tax-net operating loss carryforward-normalization-limitations on reasonable allowance in case of property of public utilities.

Headnote:

Reduction of taxpayer/common parent/regulated natural gas distributor's rate base by full amount of its ADIT account balance unreduced by balance of NOLC-related account balance would be inconsistent with Code Sec. 168(i)(9); and Reg § 1.167(l)-1 requirements.

Reference(s): Code Sec. 168; Code Sec. 167;

Full Text:

Number: **201534001**

Release Date: 8/21/2015

Index Number: 167.22-01

Third Party Communication: None

Date of Communication: Not Applicable

Person To Contact: [Redacted Text]

[Redacted Text], ID No.

Telephone Number: [Redacted Text]

Refer Reply To:

CC:PSI:B06

PLR-103300-15

Date:

May 13, 2015

LEGEND:

Taxpayer =

State A =

State B =

State C =

Commission =

Year A =

Year B =

Date A =

Date B =

Date C =

Date D =

Case =

Director =

Dear [Redacted Text]:

This letter responds to the request, dated January 9, 2015, submitted on behalf of Taxpayer for a ruling on the application of the normalization rules of the Internal Revenue Code to certain accounting and regulatory procedures, described below.

The representations set out in your letter follow.

Taxpayer is the common parent of an affiliated group of corporations and is incorporated under the laws of State A and State B. Taxpayer is engaged primarily in the businesses of regulated natural gas distribution, regulated natural gas transmission, and regulated natural gas storage. Taxpayer's regulated natural gas distribution business delivers gas to customers in several states, including State A. Taxpayer is subject to, as relevant for this ruling, the regulatory jurisdiction of Commission with respect to terms and conditions of service and as to the rates it may charge for the provision of its gas distribution service in State A. Taxpayer's rates are established on a "rate of return" basis.

Taxpayer filed a rate case application on Date A (Case). In its filing, Taxpayer's application was based on a fully forecasted test period consisting of the twelve months ending on Date B. Taxpayer updated, amended, and supplemented its data several times during the course of the proceedings. In a final order dated Date C, rates were approved by Commission for service rendered on or after Date D.

In each year from Year A to Year B, Taxpayer incurred a net operating loss carryforward (NOLC). In each of these years, Taxpayer claimed accelerated depreciation, including "bonus depreciation" on its tax returns to the extent that such depreciation was available. On its regulatory books of account, Taxpayer "normalizes" the differences between regulatory depreciation and tax depreciation. This means that, where accelerated depreciation reduces taxable income, the taxes that a taxpayer would have paid if regulatory depreciation (instead of accelerated tax depreciation) were claimed constitute "cost-free capital" to the taxpayer. A taxpayer that normalizes these differences, like Taxpayer, maintains a reserve account showing the amount of tax liability that is deferred as a result of the accelerated depreciation. This reserve is the accumulated deferred income tax (ADIT) account. Taxpayer maintains an ADIT account. In addition, Taxpayer maintains an offsetting series of entries - a "deferred tax asset" and a "deferred tax expense" - that reflect that portion of those `tax losses' which, while due to accelerated depreciation, did not actually defer tax because of the existence of an NOLC.

In the setting of utility rates in State C, a utility's rate base is offset by its ADIT balance. In its rate case filing and throughout the proceeding, Taxpayer maintained that the ADIT balance should be reduced by the amounts that Taxpayer calculates did not actually defer tax due to the presence of the NOLC, as represented in the deferred tax asset account. Thus, Taxpayer argued that the rate base should be reduced by its federal ADIT balance net of the deferred tax asset account attributable to the federal NOLC. It also asserted that the failure to reduce its rate base offset by the deferred tax asset attributable to the federal NOLC would be inconsistent with the normalization rules. The attorney general for State C argued against Taxpayer's proposed calculation of ADIT.

Commission, in its final order, agreed with Taxpayer but concluded that the ambiguity in the relevant normalization regulations warranted an assessment of the issue by the IRS and this ruling request followed.

Taxpayer requests that we rule as follows:

> 1. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balance unreduced by the balance of its NOLC-related account balance would be inconsistent with (and, hence, violative of) the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.
>
> 2. For purposes of Ruling 1 above, the use of a balance of Taxpayer's NOLC-related account that is less than the amount attributable to accelerated depreciation computed on a "last dollars deducted" basis would be inconsistent with (and, hence, violative of) the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

Law and Analysis

Section 168(f)(2) of the Code provides that the depreciation deduction determined under section 168 shall not apply to any public utility property (within the meaning of section 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, section 168(i)(9)(A)(i) of the Code requires the taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under section 168(i)(9)(A)(ii), if the amount allowable as a deduction under section 168 differs from the amount that-would be allowable as a deduction under section 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under section 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) of the Code provides that one way the requirements of section 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under section 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under section 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base.

Former section 167(l) of the Code generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former section 167(l)(3)(G) in a manner consistent with that found in section 168(i)(9)(A). Section 1.167(l)-1(a)(1) of the Income Tax Regulations provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under section 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 1.167(l)-1(h)(1)(i) provides that the reserve established for public utility property should reflect the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes.

Section 1.167(l)-1(h)(1)(iii) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the amount of the actual tax liability. This amount shall be taken into account for the taxable year in which the different methods of depreciation are used. If, however, in respect of any taxable year the use of a method of depreciation other than a subsection (1) method for purposes of determining the taxpayer's reasonable allowance under section 167(a) results in a net operating loss carryover to a year succeeding such taxable year which would not have arisen (or an increase in such carryover which would not have arisen) had the taxpayer determined his reasonable allowance under section 167(a) using a subsection (1) method, then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director.

Section 1.167(l)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. This regulation further provides that, with respect to any account, the aggregate amount allocable to deferred tax under section 167(1) shall not be reduced except to reflect the amount for any taxable year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation. That section also notes that the aggregate amount allocable to deferred taxes may be reduced to reflect the amount for any taxable year by which federal income taxes are greater by reason of the prior use of different methods of depreciation under section 1.167(l)-1(h)(1)(i) or to reflect asset retirements or the expiration of the period for depreciation used for determining the allowance for depreciation under section 167(a).

Section 1.167(l)-1(h)(6)(i) provides that, notwithstanding the provisions of subparagraph (1) of that paragraph, a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking.

Section 1.167(l)-1(h)(6)(ii) provides that, for the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under subdivision (i), above, if solely an historical period is used to determine depreciation for Federal income tax expense for ratemaking purposes, then the amount of the reserve account for that period is the amount of the reserve (determined under section 1.167(l)-1(h)(2)(i)) at the end of the historical period. If such determination is made by reference both to an historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period.

Section 1.167(l)-1(h) requires that a utility must maintain a reserve reflecting the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes. Taxpayer has done so. Section 1.167(l)-1(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Section 56(a)(1)(D) provides that, with respect to public utility property the Secretary shall prescribe the requirements of a normalization method of accounting for that section.

Regarding the first issue, § 1.167(l)-1(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Because the ADIT account, the reserve account for deferred taxes, reduces rate base, it is clear that the portion of an NOLC that is attributable to accelerated depreciation must be taken into account in calculating the amount of the reserve for deferred taxes (ADIT). Thus, to reduce Taxpayer's rate base by the full amount of its ADIT account balance unreduced by the balance of its NOLC-related account balance would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.

Regarding the second issue, § 1.167(l)-1(h)(1)(iii) makes clear that the effects of an NOLC must be taken into account for normalization purposes. Section 1.167(l)-1(h)(1)(iii) provides generally that, if, in respect of any year, the use of other than regulatory depreciation for tax purposes results in an NOLC carryover (or an increase in an NOLC which would not have arisen had the taxpayer claimed only regulatory depreciation for tax purposes), then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director. While that section provides no specific mandate on methods, it does provide that the Service has discretion to determine whether a particular method satisfies the normalization requirements. The "last dollars deducted" methodology employed by Taxpayer ensures that the portion of the NOLC attributable to accelerated depreciation is correctly taken into account by maximizing the amount of the NOLC attributable to accelerated depreciation. This methodology provides certainty and prevents the possibility of "flow through" of the benefits of accelerated depreciation to ratepayers. Under these specific facts, any method other than the "last dollars deducted" method would not provide the same level of certainty and therefore the use of any other methodology is inconsistent with the normalization rules.

This ruling is based on the representations submitted by Taxpayer and is only valid if those representations are accurate. The accuracy of these representations is subject to verification on audit.

Except as specifically determined above, no opinion is expressed or implied concerning the Federal income tax consequences of the matters described above.

This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent. In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative. W e are also sending a copy of this letter ruling to the Director.

Sincerely,

Peter C. Friedman

Senior Technician Reviewer, Branch 6

Office of the Associate Chief Counsel

(Passthroughs & Special Industries)

cc: [Redacted Text]

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 FOR RELATED APPROVALS.)	DOCKET NO. E-04204A-15-______

Direct Testimony of

Michael E. Sheehan

on Behalf of

UNS Electric, Inc.

May 5, 2015

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Michael E. Sheehan. My business address is 88 East Broadway Blvd., Tucson, Arizona 85701.

Q. What is your position with UNS Electric, Inc. ("UNS Electric" or the "Company")?

A. I am the Senior Director of Fuels and Resource Planning.

Q. Please describe your education and experience.

A. I received a Bachelor of Science degree in Management Information Systems from the University of Arizona in 1991. I was hired by Tucson Electric Power Company ("TEP") in 1993. In 1996, I moved into TEP's Resource Planning Department as a Supply-Side Analyst. I was promoted to Manager of Resource Planning in 2001 and Director in 2011. I have been in my current role since February 2015.

Q. What is the purpose of your Direct Testimony?

A. I discuss UNS Electric's acquisition of a 25% share of Unit 3 at the Gila River Power Plant ("Gila River") from a resource planning perspective. This acquisition should prove highly beneficial to our customers over the long-run due to a favorable purchase price, a highly efficient heat rate, and the custom-sized nature of this resource addition. I further testify to the expected benefits and cost savings to both UNS Electric and its customers. Further, I provide an estimate on the annual O&M costs associated with the operations of Gila River as well as an estimate on the base cost of fuel for the time period new rates would go into effect. Finally, the acquisition of the 25% interest in Gila River is in the public interest.

II. OVERVIEW ON UNS ELECTRIC'S RESOURCE PLANNING ACTIVITIES.

Q. Please provide an overview on UNS Electric's customer base.

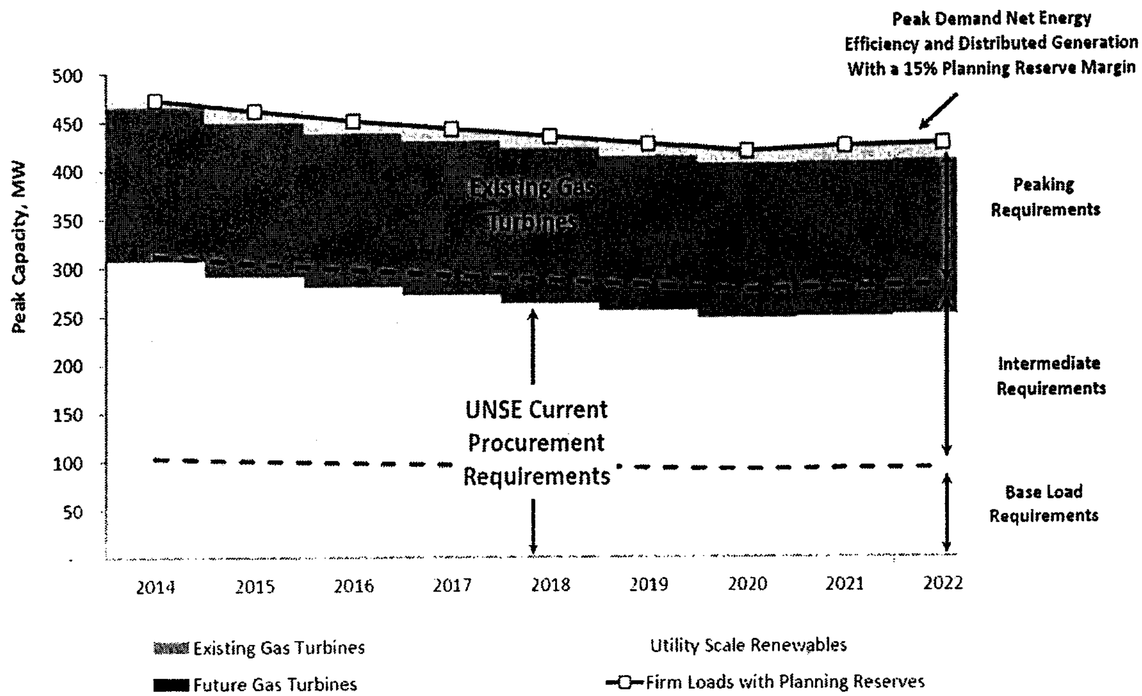
A. UNS Electric provides electricity to approximately 93,000 customers in two geographically distinct areas. In northwest Arizona, UNS Electric provides service to the majority of Mohave County. This segment of the service territory includes approximately 73,000 customers located primarily in the Kingman and Lake Havasu City areas. In addition to Mohave County, UNS Electric also provides service to the majority of Santa Cruz County in southern Arizona. This southern service territory includes approximately 19,000 customers located primarily in the Nogales area.

Q. Can you provide a summary of the load and resource assumptions outlined in UNS Electric's 2014 Integrated Resource Plan ("IRP")?

A. UNS Electric's long-term load obligations net of energy efficiency and distributed generation, including operating reserves will require UNS Electric to plan for approximately 425 – 475 MW in capacity resources from 2014 – 2022. Prior to the acquisition of Gila River, the Company's generation assets were limited to simple cycle natural gas combustion turbines that were used primarily to serve summer on-peak demand and reserve capacity requirements. These existing facilities include the Black Mountain Generating Station (90 MW) located in Mohave County, and the Valencia Generating Station (63 MW) located in Nogales. The majority of UNS Electric's load requirements were served primarily through a variety of short-term purchased power contracts sourced from the wholesale energy and capacity market at Palo Verde.

As shown in Chart 1 below[1], the Company's resource requirements are divided between base load, intermediate and peaking requirements. Since UNS Electric currently has 153 MW of peaking capacity located at the Black Mountain and Valencia Generating stations, its future capacity requirements were forecasted to include approximately 100 – 150 MW of base load resources and 150 – 200 MW of intermediate resources.

Chart 1 – UNS Electric's Future Capacity Needs



Q. Describe why UNS Electric purchased an interest in Gila River?

A. The acquisition of a 25% interest in Gila River satisfied the Company's base load and intermediate resource needs under the precise circumstances articulated in UNS Electric's 2012 and 2014 Integrated Resource Plans. Citing the high cost of new construction and

[1] 2014 UNS Electric's Integrated Resource Plan (filed in Docket No. E-00000A-13-0070) ("2014 UNS Electric Integrated Resource Plan") at 243.

UNS Electric's over dependence on the wholesale market, the 2012 IRP contemplated this type of future acquisition as part of its three year action plan:

> "Given UNS Electric's need for future base load and intermediate resources, as well as firming capacity for intermittent renewable resources, UNS Electric will monitor the market for economically attractive plant acquisition opportunities. A low cost, multi-owner acquisition of an existing combined cycle gas fired plant would enable UNS Electric to firm up its longer term capacity needs while realizing economies of scale through a multi-owner plant configuration."[2]

Q. Did the Staff of the Arizona Corporation Commission ("Commission") raise any resource planning concerns regarding UNS Electric's 2012 IRP?

A. Yes. One issue in particular was directly related to UNS Electric's over reliance on future short term market purchases. Both Staff and its IRP consultant stated in the 2012 IRP Staff Report and again in the related Commission Decision No. 73884 (May 8, 2013) the following:

> "The cost and availability of future short-term market purchases are subject to a wide array of influences that are difficult, if not impossible, to predict. For example, if a large number of older coal-fired generating plants are retired in the western region, the availability of such purchases will decline dramatically, and the cost of such purchases will increase significantly. Reliance on short-term market purchases in a long-term plan is difficult, if not impossible, to justify."[3]

Q. Are Staff's concerns regarding reliance on future short-term market purchases unwarranted?

A. No. In fact, the Company agrees with the Staff assessment regarding the previous over-reliance on short-term market purchases in the Company's long-term resource plans. The Company detailed its rationale for acquiring Gila River in its application for an accounting order filed with the Commission on December 31, 2013.

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[2] 2012 UNS Electric's Integrated Resource Plan (filed in Docket No. E-00000A-11-0113 ("2012 UNS Electric Integrated Resource Plan") at 26.
[3] Decision No. 73884 at 4.

> "UNS Electric's heavy reliance on wholesale power has not proven problematic in recent years where affordably priced resources have been widely available. Over the long term, though, the Company's customers could face significantly higher rates and potential reliability concerns if coal plant closures, carbon costs, increased growth rates or other market forces drive up energy and capacity costs and restrict the availability of market resources. The Commission acknowledged this risk in May 2013 when it advised UNS Electric and other load serving entities about future short-term market purchases in their long-term Integrated Resource Plans."[4]

Q Has Staff addressed resource adequacy and the potential cost impacts on the regional wholesale market?

A. Yes. In UNS Electric's recent financing docket, Staff made several observations on the wholesale market that were similar to UNS Electric's assessment on longer term capacity in the wholesale market. Staff noted that:

> "Staff does believe there will be reductions in available firm power in the market place and resulting upward pressure on prices over the next five to ten years for two main reasons that support UNS Electric locking in capacity at this time. First, there is a projected decline of available capacity in the market place. Based upon the Western Electricity Coordinating Council's ("WECC") 2013 Resource Adequacy Report, the desert southwest is projected to reach the reference reserve margin of 13.6% by 2020. This analysis did not reflect the retirement of Four Corners 1, 2 & 3 (560 MW) and the potential retirement within this time frame of one Navajo Generating Unit (750 MW), and San Juan 2 & 3 (800 MW) for a total of 2,110 MW. This would reduce the reserves in the region to 7%."[5]

The limited reserve margin identified by Staff is important because, under Arizona's IRP planning rules, load serving entities must target a 15% reserve margin criteria. Staff further stated that:

> "Second, there may be a potential increase in demand for natural gas combined cycle units based upon the Environmental Protection Agency's proposed carbon reduction rules (Clean Power Plan 111(d)) for existing power plants that was released on June 2, 2014. One major component of the proposed rules calls for

[4] UNS Electric Inc.'s Application in Docket No. E-04204A-13-0476 at 2.

[5] Staff Report, Attachment A, (Engineering Analysis) at 11 (UNS Electric Inc. Financing Application (Docket No. E-04204A-13-0447)).

reliance on increased dispatch of natural gas combined cycle generating units to reduce coal generation dispatch."[6]

Moreover, in addition to early coal plant retirements and future environmental regulations under the Environmental Protection Agency's ("EPA") proposed Clean Power Plan, increased demand for wholesale market exports may also be a contributing factor resulting in near-term upward price pressure for energy and capacity. For example, the California ISO's decision to move forward with the construction of a second 500 kV circuit from the California border to the Palo Verde electricity trading hub demonstrates this growing demand. In July 2014, the California ISO proposed moving forward with the Delaney-Colorado River transmission project that plans to interconnect a 500 kV transmission line from the Colorado River substation in California to the Delany substation in Arizona. Staff drew similar conclusions on how the increased demand from California may influence the demand for natural gas capacity in Arizona:

"It is also conjectured that this could result in California expanding to adjacent states to facilitate EPA's rule implementation which could impact Arizona. These factors may also put upward pressure on the value of existing combined cycle generating units in the region."[7]

These concerns over future availability of economic wholesale energy or generation assets further highlight and confirm the benefits of acquiring Gila River at this time and at this price.

[6] Id. at 11.
[7] Id. at 11.

III. OVERVIEW ON GILA RIVER UNIT 3 AND THE ACQUISITION PROCESS.

Q. Please provide a general description of the Gila River Power Plant.

A. The Gila River Power Plant is located approximately 75 miles southwest of Phoenix and about 30 miles south of the Palo Verde trading hub. Gila River Power Plant is a modern, efficient natural-gas combined-cycle facility that is geographically situated to provide reliable, base load and intermediate power to UNS Electric's customers in both Mohave and Santa Cruz counties. It is sited on approximately 1,100 acres within the town of Gila Bend. The plant consists of four power blocks or units with each representing 550 MW of nominal capacity. At 2,200 MW of combined capacity, Gila River is the largest natural gas-fired generating facility in the WECC market zone. Gila River went into commercial operation in July 2003.

Q. Please describe the procurement process for Gila River.

A. In the 2012 Resource Plan, UNS Electric made a commitment to actively monitor the wholesale merchant market for potential resource alternatives as part of its on-going resource procurement process. In May 2013, TEP conducted a Request for Proposal ("RFP") to evaluate the wholesale merchant market for potential capacity alternatives. As a result, TEP received fourteen different proposals from nine different bidders. Based on the bid analysis, Gila River Power LLC's proposal for Gila River was chosen as the final bidder due to the economic and operational advantages of that proposal. Due to the unique opportunity to right-size the capacity to be acquired by UNS Electric, as well as the Company's need for base load generating capacity, it made sense for UNS Electric to acquire a portion of Gila River through TEP's 2013 RFP process. The combination of both TEP's and UNS Electric's capacity needs enabled UNS Electric to jointly acquire an appropriately-sized resource at a clear and significant discount to other alternatives. The purchase price of approximately $398 per kW was the lowest cost bid from the RFP and is significantly lower than the cost of building a new facility.

Q. Where there any other factors which made this acquisition a unique opportunity?

A. Yes. In August of 2013, the merchant owner of Gila River was experiencing financial difficulties due to poor wholesale market conditions. As a result, the bid proposal for Gila River was contingent on the buyer completing its due diligence on the facility and committing to purchase the asset in less than four months. TEP and UNS Electric were able to meet these contingencies and in December 2013 both Companies entered into a power purchase agreement with Gila River Power LLC, a subsidiary of Entegra Power Group LLC to purchase Gila River at the Gila River Power Plant. The purchase price for UNS Electric's share was approximately $55 million, or approximately $398 per kW, for 138 MW of capacity.

Q. You mentioned that there were additional operational benefits associated with the Gila River acquisition.

A. Yes. In addition to being the lowest cost resource option, Gila River is strategically situated to take advantage of gas transportation from both the El Paso Natural Gas and Transwestern Pipeline Company pipelines, providing access to the Permian, San Juan supply basins. The ability to source fuel for Gila River from two different supply basins as well as two different gas pipeline companies offers significant operational advantages from a cost and reliability basis.

Further, Gila River interconnection to the Palo Verde market hub and existing transmission rights to Jojoba Switchyard also resulted in lower transmission costs relative to other proposals. Finally, with the acquisition of Gila River in December 2014, work was completed to transfer Gila River into TEP's balancing authority. This coordination with

TEP's balancing authority will enable both TEP and UNS Electric to fully optimize the dispatch of the unit for its retail customers.

Q. Did TEP use an independent monitor in the 2013 RFP?

A. Yes. The Accion Group, Inc. was selected by TEP to serve as the Independent Monitor ("IM") for its 2013 Power Plant Purchase RFP. The Accion Group Inc. provided oversight on the RFP process and reviewed the analysis on the final evaluations. The results of the final report from the independent monitor were provided to Staff in UNS Electric's recent financing docket (Docket No. E-04204A-13-0447):

> "Staff also reviewed, under a protective agreement, TEP's RFP for a Power Plant Purchase and related results as well as a report by UNS Electric on its analysis of purchasing a 25 percent interest in Gila River. TEP used an independent monitor to ensure fair and equal treatment of all bidders, ensuring all potential bidders had access to the same information at the same time. A number of proposals for existing and new facilities, offering both ownership and short-term power purchase agreements with options to purchase the power plant at a later time were received by TEP. Based upon TEPs analysis of all alternatives, TEP selected Gila River because it found it to be the lowest cost intermediate/baseload plant offered in the RFP"[8]

IV. GILA RIVER UNIT 3 FINANCIAL ANALYSIS.

Q. Did the Company perform an analysis comparing the purchase of Gila River with the construction of a new facility?

A. Yes. UNS Electric's 2014 IRP compared the acquisition of Gila River with the cost of building a similar unit. A comparison of the levelized cost of electricity ("LCOE")[9] of the proposed acquisition versus new build construction is shown below. Exhibit 1 shows the

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[8] Id. at 9.

[9] LCOE is a measure of the overall competiveness of different generating technologies. It represents the per-megawatt hour cost of owning and operating a generating plant over an assumed life and duty cycle. Key inputs to calculating LCOE include capital costs, fuel costs, fixed and variable operations and maintenance ("O&M") costs, financing costs, and an assumed utilization rate for each plant type.

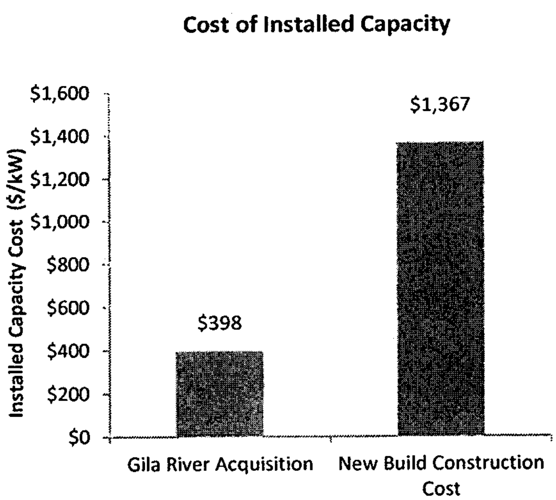
levelized cost for Gila River is estimated at approximately \$79.72/MWh whereas the levelized cost for new build construction is estimated at \$117.40/MWh. In addition, UNS Electric's share of Gila River is much less expensive than a similar commitment in a newly constructed combined cycle plant. The Gila River purchase price of \$398/kW is approximately one-third the cost of new construction at \$1,367/kW, which results in a \$143 million net present value benefit for UNS Electric's customers over the next fifteen years.

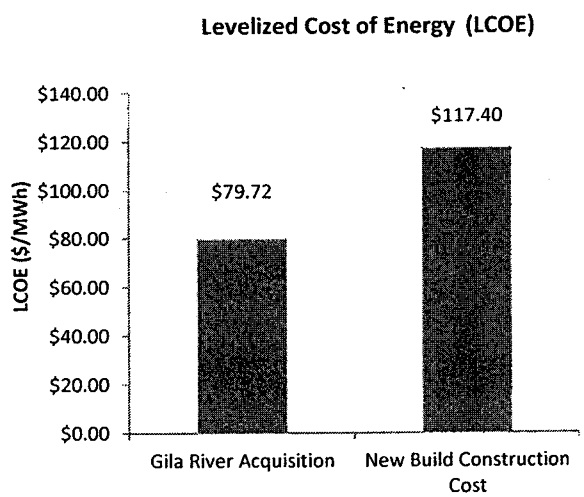
Exhibit 1 - Gila River vs. New Construction Cost Comparison[10]

Unit Capacity, MW	137.5
Weighted Average Cost of Capital, WACC	7.83%
Levelized Cost of Fuel, \$/mmBtu	\$6.54
Average Capacity Factor, %	41.7%

15 Year NPV and LCOE (2015-2029)	Gila River Acquisition	New Construction
Cost of Installed Capacity	\$54,750	\$187,963
Cost of Installed Capacity, \$/kW	\$398	\$1,367
NPV Revenue Requirements, \$000	\$323,851	\$466,828
Levelized Cost of Energy, LCOE, \$/MWh	\$79.72	\$117.40

NPV Revenue Requirement Savings, \$000	\$142,978





[10] This exhibit was also included in the 2014 UNS Electric Integrated Resource Plan at 246.

Q. Was there any independent analysis done to validate UNS Electric's assumptions on the installed cost of new combined cycle power plants?

A. Yes. As part of its analysis in Docket No. E-04204A-13-0447, Staff conducted its own independent review on UNS Electric's cost assumptions, stating:

> "Staff's independent review of the installed cost of a new combined cycle power plant in the size range of Gila River found estimates ranging from \$950/kW to \$1,475/kW in 2014 dollars. While UNS Electric's estimate of \$1,320/kW is at the higher end of this range, the price of \$398/kW being paid by UNS Electric for Gila River is about 60 percent below even the lowest estimate for a new plant identified by Staff."[11]

Q. Were there any recent plant acquisitions that could provide a market based comparison against the acquisition cost of Gila River?

A. Yes. As part of its analysis in Docket No. E-04204A-13-0477, Staff referenced the sale of Unit 1 at the Mesquite Generating Station located near Palo Verde. In 2012, the Salt River Project acquired one of the two 600 MW natural gas combined cycle power blocks from Sempra Energy.

> "A point of reference for the capital cost of purchasing an existing plant is Salt River Project's ("SRP") acquisition of one power block at the Mesquite Generating Station combined cycle gas turbine plant located near Gila River and installed in 2002. SRP announced its intention to acquire Mesquite in December 2012. The acquisition price equated to approximately \$594/kW, about 50 percent greater than the price agreed to by TEP and UNS Electric for Gila River."[12]

Relative to the acquisition price of \$594/kW referenced above, UNS Electric realized acquisition savings of approximately \$27 million[13] through the purchase of Gila River.

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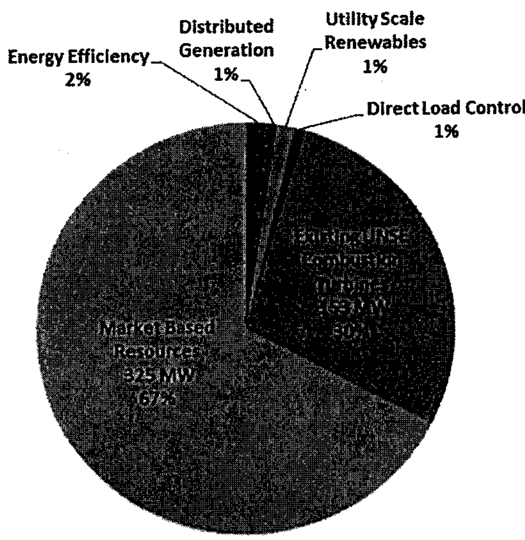
[11] Staff Report, Attachment A, (Engineering Analysis) at 8 (UNS Electric Inc. Financing Application (Docket No. E-04204A-13-0447)).
[12] Id. at 9.
[13] Hypothetical market based acquisition savings - \$26,950,000 = (594 \$/KW - 398 \$/kW) * 137,500 kW.

V. GILA RIVER UNIT 3'S IMPACT ON PORTFOLIO DIVERSIFICATION.

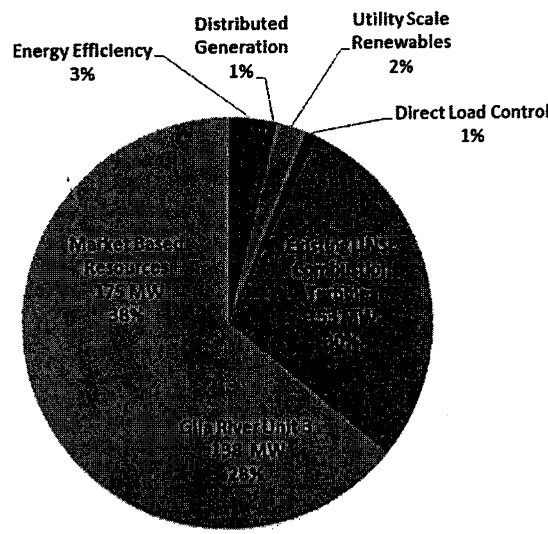
Q. Can you summarize UNS Electric's resource capacity before and after the acquisition of Gila River?

A. UNS Electric's acquisition of Gila River reduced its market based capacity exposure from approximately 325 MW in 2014 to 175 MW in 2015. The charts below depict the change in UNS Electric's resource capacity mix. Gila River is represented by the 138 MW of combined cycle capacity in the chart on the right."[14]

Chart 2



UNSE Capacity Prior to Gila River Acquistion



UNSE Capacity After the Gila River Acquistion

The Gila River acquisition significantly reduces UNS Electric's overall reliance on market based capacity. However, it did not reduce it beyond appropriate levels. Staff has noted that UNS Electric's reliance on short-term wholesale markets is still higher than other Arizona utilities:

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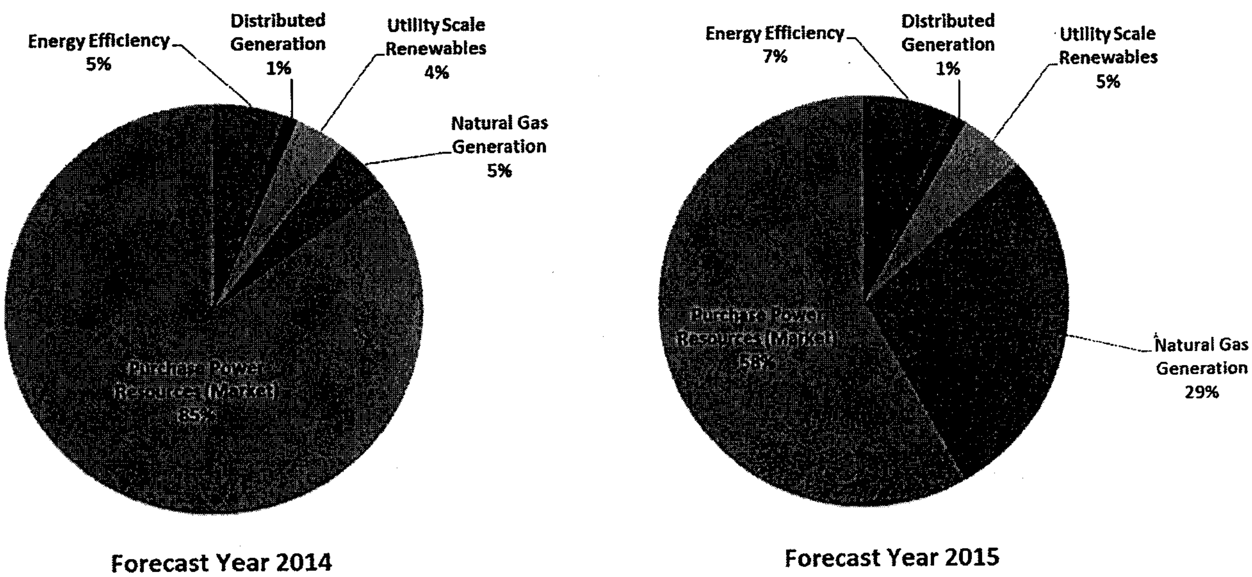
[14] 2014 UNS Electric Integrated Resource Plan at 248.

"The acquisition of Gila River will reduce UNS Electric's reliance on the short term market from approximately 67 percent of its capacity needs to approximately 38 percent. While a significant reduction, UNS Electric's reliance on short term market purchases is still substantially higher than other utilities in Arizona and higher than suggested in the 2012 IRP Staff report."[15]

Q. How are UNS Electric's purchase power requirements (on an energy basis) expected to change since the acquisition of Gila River?

A. Based on UNS Electric's 2014 IRP assumptions, the Company's total percentage of projected purchase power resources in 2014 was approximately 85% of its total resource mix. After the acquisition of Gila River, UNS Electric's total percentage of purchase power is expected to drop to approximately 58% with the balance of resources sourced from natural gas, renewables and energy efficiency.[16]

Chart 3



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[15] Staff Report, Attachment A, (Engineering Analysis) at 10 (UNS Electric Inc. Financing Application (Docket No. E-04204A-13-0447)).
[16] 2014 UNS Electric Integrated Resource Plan at 251.

VI. UNS ELECTRIC'S ESTIMATE OF O&M FOR GILA RIVER UNIT 3.

Q. Is the Company providing an estimate of annual O&M for Gila River?

A. Yes. Due to the timing of the Gila River acquisition,[17] as well as differences in the operation and accounting for Gila River under a merchant owner, UNS Electric has not had adequate time to adjust historical O&M spending for the unit to reflect anticipated O&M spending. As a proxy for actual experience running Gila River, UNS Electric is relying on actual historical O&M cost from TEP's ownership interest in the Luna Energy Facility ("Luna") to estimate Gila River's future O&M costs. TEP currently shares a one-third ownership share of Luna with Public Service of New Mexico ("PNM") and Freeport McMoRan Inc. ("FMI").[18] Luna is located in Deming, New Mexico and went into service in 2006.

Q. Why would the use of Luna O&M cost data be appropriate?

A. Both Unit 3 at Gila River and Luna are similarly sized natural gas-fired combined cycle generating facilities. Each facility is comprised of a single power block that consists of 2 combustion turbines and 1 steam turbine. Both power blocks are of similar nominal capacity. Gila River is a nominal 550 MW power block, while Luna is rated at a nominal 555 MW. Both facilities utilize General Electric ("GE") 7FA+e gas turbines with an associated heat recovery steam generator and one GE D11 steam turbine with accompanying cooling towers. TEP has a long-term service maintenance agreement ("LTSA") with GE and coordinates its maintenance with a third party O&M provider North American Energy Services ("NAES"). Gila River utilizes a third party O&M

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[17] UNS Electric's closing date for the Gila River acquisition was December 10, 2014.

[18] In October 2014, Samchully Asset Management and Macquarie Funds Group entered into an agreement to acquire FMI's share of the Luna Energy Facility. Under this agreement, FMI will retain the ability to purchase up to the full amount of its previous ownership share of the Luna facility of approximately 185 MW, thereby continuing to be active participant in the operations of the facility.

provider Ethos Energy[19] to perform the full range of annual preventative and routine maintenance. Both O&M providers follow similar original equipment manufacturers ("OEM") maintenance practices for both the major and non-major maintenance requirements. Non-major maintenance for the gas turbines are performed primarily utilizing the OEM recommendations from GE and GE technical information letters ("TILS") as guidelines. The turbine's major maintenance is performed in compliance with the GE's Heavy-Duty Gas Turbine Operating and Maintenance Considerations publication, GER 3620L, which provides the hours and starts criteria recommendations to identify the timing of the inspections and major overhauls. The balance of plant maintenance activities (boiler feed pumps, condensate system, cooling water systems, continuing emissions monitoring systems and fire protection systems) are conducted in accordance with OEM recommendations and on an as needed corrective maintenance basis. Table 1 below details each plant's similarities.

Table 1

Unit Characteristics	Luna Energy Facility	Gila River Unit 3
Year in Service	2006	2003
Unit Capacity	555	550
Manufacturer	General Electric	General Electric
Configuration	2x1 NGCC	2x1 NGCC
O&M Provider	NAES	Ethos Energy
Ownership Share	33%	25%

[19] Ethos Energy Power Plant Services, LLC, a Nevada limited liability company (f/k/a Wood Group Power Plant Services, LLC).

Q. What are the annual O&M costs associated with operating Luna?

A. Based on TEP's ownership share, historical non-fuel O&M expenses at Luna have averaged approximately $4.6 million per year from 2008-2013. The O&M costs account for annual routine and preventive maintenance on the power block, the plant common facilities and the switchyard. O&M costs associated with unit overhauls and major maintenance are also included in this amount. Table 2 below summarizes the total annual O&M costs in dollars and dollars per kW-year at Luna.[20]

Table 2

TEP's Share of O&M (2008-2013)	Luna Energy Facility
Annual O&M, $	$4,534,904
Luna Nominal Capacity, MW	185
Luna Annual O&M, $/kW-year	$24.51

Q. How do the Luna O&M costs translate into O&M costs for UNS Electric's share of Gila River?

A. The O&M costs for UNS Electric's share of Gila River are derived by multiplying The Luna Energy Facility costs on a $/kW-year by the UNS Electric's 25% ownership share of Gila River unit (137.5 MW). The results of this adjustment estimate UNS Electric's share of O&M at Gila River to be $3.4 million per year. These cost estimates shown below in Table 3.

Table 3

Gila River O&M Proforma Adjustment	Gila River
UNS Electric's Gila River Nominal Capacity, MW	137.5
Luna Annual O&M, $/kW-year	$24.51
UNS Electric's Share of Annual O&M, $	$3,370,537

[20] These costs reflect the average annual O&M costs incurred from 2008 through 2013 (FERC Form 1).

VII. UNS ELECTRIC'S ESTIMATE OF THE BASE COST OF FUEL.

Q. Does the Company have an estimate on the average cost of fuel and purchase power for the timeframe that proposed UNS Electric rates are likely to go into effect.

A. Yes. As part of this rate case filing, UNS Electric's Resource Planning group updated its long term production cost model AuroraXMP.[21] AuroraXMP is currently used for determining the forward pricing projection for UNS Electric's cost of fuel and purchase power. Based on forward natural gas and wholesale price projections as of April 2015,[22] UNS Electric forecasts the average cost of fuel and purchase power to be approximately 4.8427 ¢/kWh. The cost estimate in Table 4 below assumes PPFAC eligible costs from April 1, 2016 through March 31, 2017.

Table 4

UNS Electric Cost of Fuel & Purchase Power	April 2016 - March 2017
PPFAC Eligible Cost, $000	$ 77,531
UNS Electric Retail Sales, GWh	1,601
Average Annual Cost, ¢/kWh	4.8427

Forward Market Prices	April 2016 - March 2017
Palo Verde (7x24) Market, $/MWh	$ 29.70
Permian Natural Gas, $/mmBtu	$ 3.03

VIII. CONCLUSIONS.

Q. Why should the Commission find the purchase of Gila River to be prudent and in the public interest and include the facility in rate base?

A. There are several factors supporting the Company's position that the purchase of Gila River was prudent and is in the public interest. To summarize, those factors include: (i)

[21] AuroraXMP, Power Generation Forecasting Software by EPIS, http://epis.com/.

[22] Tullet Liberty, West Power Prices and ICE Natural Gas Futures (April 2015).

Gila River is a highly efficient generation resource suited to meet the Company's future load requirements, as well as provide firming capacity for intermittent renewable resources; (ii) as demonstrated from the RFP process, the cost of acquiring Gila River was significantly less expensive than other market acquisitions as well as new build construction; and (iii) ownership of Gila River reduces the Company's reliance on the wholesale power markets, thus reducing risk to UNS Electric's customers by minimizing unpredictable swings in wholesale market costs.

Q. Is this conclusion supported by analysis previously prepared by the ACC Staff?

A. Yes. One of Staff's final conclusions in Docket No. E-04204A-13-0447 was as follows:

> "Based upon Staffs review of UNS Electric's economic analysis and the Company's need to reduce its reliance on short term market purchases, Staff concludes the acquisition of Gila River appears reasonable."[23]

Q. Does this conclude your testimony?

A. Yes.

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[23] Staff Report, Attachment A, (Engineering Analysis) at 12 (UNS Electric Inc. Financing Application (Docket No. E-04204A-13-0447)).

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE – INTERIM CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
VACANT

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

Rebuttal Testimony of

Michael E. Sheehan

on Behalf of

UNS Electric, Inc.

January 19, 2016

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Michael E. Sheehan and my business address is 88 East Broadway Blvd., Tucson, Arizona, 85701.

Q. Did you file Direct Testimony on behalf of UNS Electric Inc. ("UNS Electric" or "Company") in this proceeding?

A. Yes.

Q. Which testimony do you address in your Rebuttal Testimony?

A. My Rebuttal Testimony addresses both the Direct Testimony and the Direct Rate Design Testimony of Staff witness Barbara Keene.

Q. What specific issues do you address in your testimony?

A. First, I address Staff's concerns on the Company's methodology for determining the base cost of fuel. Second, I address the Company's proposed Base Rate Annual Adjustment, and lastly, I address the Company's proposed PPFAC Percentage Rate Adjustment.

Q. What objections did Staff raise regarding this issues?

A. For the base cost of fuel, Staff recommended an alternative methodology for calculating the average cost of fuel and purchased power. Regarding the Base Rate Annual Adjustment and the PPFAC Percentage Rate Adjustment, Staff objected to our changes on the basis that the Company's proposal added a great amount complexity to the PPFAC Plan of Administration and the adjustments shifted costs among customer classes.

Q. Does the Company agree with Staff positions?

A. Regarding the alternative methodology for determining the base cost of fuel, the Company agreed with Staff's position. As part of this filing, the Company is providing an updated estimate for the average cost of fuel and purchased power based Staff's methodology. In terms of the two PPFAC adjustments, the Base Rate Annual Adjustment and the PPFAC Percentage Rate Adjustment, the Company concedes that while the proposals add some complexities to the PPFAC Plan of Administration, the Company believes that these proposed changes will provide more accurate and equitable price signals and improve the Company's overall rate design for customers.

II. BASE COST OF FUEL AND PURCHASED POWER UPDATE.

Q. Is the Company proposing a revision to the base cost of fuel and purchased power?

A. Yes. The Company is updating its base cost of fuel and purchased power rate using Staff's calculation methodology[1] and actual costs from 2015.

Q. What was UNSE's average cost of fuel and purchased power in 2015?

A. Using Staff's calculation methodology, UNSE's average cost of fuel and purchased power in 2015 was $0.053689 per kWh. This is based on the actual 2015 fuel and purchased power costs of $87,301,407 and retail sales of 1,626,067,036 kWh.

Q. Do you have any other recommendations regarding the proposed base cost of fuel and purchased power?

A. Yes. The Company is proposing to update the base cost of fuel and purchased power rate based on the Company's actual fuel costs prior to establishing new base fuel rates in this proceeding. This update could potentially provide UNSE customers with a lower base

[1] Staff's calculation methodology is described on Pages 8 and 9 of Direct Testimony of Barbara Keene

cost of fuel and purchased power rate when new rates go into effect. This benefits customers by ensuring that the base cost of fuel and purchase power is reflective of current market conditions.

III. BASE FUEL RATE ANNUAL ADJUSTMENT.

Q. In light of Staff's testimony does the Company still support the Base Rate Annual Adjustment?

A. Yes. The Company believes that the Base Rate Annual Adjustment will provide another tool for the Company to improve its overall rate design for customers. This proposed change will adjust the base cost of fuel and purchased power rate annually resulting in a more accurate and timely recovery of base power supply costs.

Q. What is the purpose of the Base Rate Annual Adjustment?

A. The Base Rate Annual Adjustment is designed to reduce the difference between the actual and approved collections of the base power supply costs related to changes in customer usage patterns relative to the test year.

Q. Can you provide an example on how this adjustment would work?

A. Yes. For example, based on the actual base cost of fuel and purchased power, the Company's 2015 power supply costs were $0.053689 per kWh. However, if over the next 12-months, the changes in customer usage patterns result in the actual recovery of the base power supply costs collecting $0.055218 per kWh (a 2.85% over-recovery of base fuel rates), then the Base Rate Annual Adjustment would be used to adjust all base fuel rates downward by 2.85% to minimize this over recovery in subsequent years. Conversely, if the actual recovery of the base power supply costs had under-recovered by 2.85%, then the Base Rate Annual Adjustment would be used to adjust all base fuel rates upward by 2.85% to minimize this under-recovery. This Base Rate Annual Adjustment would be applied once a year based on 12-months of actual collections.

Q. Doesn't the monthly changes to the PPFAC rate account for this type of variance in the actual base power supply recovery?

A. No. The adjustments to the monthly PPFAC rate only account for changes related to the 12-month rolling average cost of fuel and purchased power. The current UNS Electric PPFAC Plan of Administration currently has no mechanism to deal with the base power supply collection variances caused as a direct result of changing customer composition and usage patterns.

Q. What are the implications of not implementing this Base Rate Annual Adjustment?

A. This difference between the expected recovery based on the base power supply costs established in the rate case and the actual recovery of base power supply costs ends up in the PPFAC bank balance. While the Company will eventually recover or refund this bank balance to customers, this process may take several years to occur. By making an annual adjustment to base power supply rate, any over or under collection will be refunded or charged to customers[2] over the course of the subsequent 12 months.

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[2] In a time of unprecedented change in energy efficiency technologies, distributed generation and a continuing trend of lower use per customer, the Base Rate Annual Adjustment enhances the PPFAC Plan of Administration with an annual mechanism that supports the "Matching Principle" where customers are better aligned to receive the direct cost or benefit based on their actual use of the system. In addition, this matching of fuel and purchased power costs with the rates the Company uses to recover those costs allows rates to reflect the "Cost Causation Principle." Since the PPFAC only recovers changes at the margin, the Base Rate Annual Adjustment reflects the full value of the cost change so that the timing mismatch under the PPFAC is minimized on an annual basis.

IV. PPFAC PERCENTAGE RATE ADJUSTMENT.

Q. Does the Company still support the concept of a PPFAC percentage rate adjustment?

A. Yes. The Company believes that a PPFAC percentage rate adjustment results in an improved allocation of power supply costs by customer class based on the actual cost to serve these customer classes and the structure of their rates.

Q. Please describe the Company's proposal to apply a PPFAC rate as a percentage of base fuel costs?

A. Each customer class rate schedule has a base power supply rate component. These base power supply rate components differ by customer class, by time of use and by season. Currently, the PPFAC rate is applied on a dollar per kWh basis equally across all customer classes and rate schedules and has no relationship to the customer's original base power supply rate. As a result, the Company is proposing to refund or collect the PPFAC as a percentage of each customer's class's underlying base power supply charge.

Q. Would you explain how the PPFAC rate is applied to UNSE customers under the existing PPFAC Plan of Administration?

A. The current PPFAC rate is applied equally on a dollar per kWh basis across all customer rate classes. For example, as shown in Table 1 below, if the actual cost of fuel and purchased power for the total Company was \$0.049531 per kWh, and the actual amount collected through base rates was \$0.054375 per kWh, the current application of the PPFAC rate would decrease all power supply costs by \$0.004844 per kWh for all customer classes.

Table 1 – Power Supply Assumptions (Total Company)[3]

PPFAC Rate Change Assumptions	
Existing PPFAC Rate, $/kWh	$0.054375
New PPFAC Rate, $/kWh	$0.049531

PPFAC Rate, $/KWh	-$0.004844
PPFAC Rate, %	-8.91%

Applying the PPFAC rate for all customers on the same per kWh rate, results in an 8.75% decrease to the base power supply rate for Residential Service class customers and 10.44% decrease to the base power supply rate for Large Power Service class customers. Table 2 below shows the current application of the PPFAC rate change on a dollar per kWh basis by rate class.

Table 2 – Current Rate Change Methodology (By Rate Class)[4]

UNSE Customer Rate Class	Existing Base Power Supply Rate $/kWh	PPFAC Rate $/kWh	Net Power Supply Rate $/kWh	Rate Impact %
Residential Service	$0.055342	-$0.004844	$0.050498	-8.75%
Small General Service	$0.054575	-$0.004844	$0.049732	-8.88%
General Service	$0.054229	-$0.004844	$0.049386	-8.93%
Large Power Service	$0.046384	-$0.004844	$0.041540	-10.44%
Total Company	$0.054375	-$0.004844	$0.049531	-8.91%

Q. Would you explain how the Company's proposed PPFAC percentage rate would be applied to UNSE's customers?

A. Using the same assumptions shown in Table 1 above, the PPFAC percentage rate would result in a decrease of 8.91% applied to the individual base power supply rates for each customer rate class. On a customer class basis, this results in a $0.004930 per kWh decrease for Residential Service customers compared with a $0.004132 per kWh

[3] [Existing Base Power Supply Rate, $/kWh - New Net Power Supply Rate, $/kWh = PPFAC Rate $/kWh]
[New Net Power Supply Rate, $/kWh / Existing Base Power Supply Rate, $/kWh -1 = PPFAC Rate %]

[4] The dollar per kWh numbers shown in Table 2 are representative of UNSE's average fuel and purchased power costs and will differ from the actual numbers presented in the Company's actual cost of service rate design testimony.
[Existing Base Power Supply Rate, $/kWh + PPFAC Rate, $/kWh = Net Power Supply Rate, $/kWh]

decrease for Large Power Service customers. Table 3 below shows the application of the PPFAC percentage rate and the resulting dollar per kWh rates by customer class.

Table 3 – Proposed Rate Change Methodology (By Rate Class)[5]

UNSE Customer Rate Class	Base Power Supply Rate $/kWh	PPFAC % Rate Change %	Net Power Supply Rate $/kWh	Rate Impact $/kWh
Residential Service	$0.055342	-8.908%	$0.050412	-$0.004930
Small General Service	$0.054575	-8.908%	$0.049714	-$0.004862
General Service	$0.054229	-8.908%	$0.049399	-$0.004831
Large Power Service	$0.046384	-8.908%	$0.042252	-$0.004132
Total Company	$0.054375	-8.908%	$0.049531	-$0.004844

Q. Why is the Company's proposed PPFAC percentage rate an improvement over the current PPFAC rate calculation?

A. The proposed PPFAC percentage rate applies changes to the PPFAC rate on a more equitable basis across the individual rate classes. The percentage rate applies changes to the PPFAC in a manner that better maintains the original cost of service allocations that are approved as part of a general rate case.

Q. Why is the PPFAC percentage rate more equable by rate class?

A. In comparing the load characteristics of UNSE customers, we observe that Residential Service customers incur higher fuel and purchased power costs on a dollar per kWh basis than Large Power Service customers. This is based on the fact that Residential Service customers have a lower load factor and incur higher distribution losses than Large Power Service customers. This cost differential is represented in the Company's proposed cost of service rate design. Exhibits MES-R-1 and MES-R-2 show the annual hourly load profiles for both the Residential Service and Large Power Service customers. In addition

[5] The dollar per kWh numbers shown in Table 3 are representative of UNSE's average fuel and purchased power costs and will differ from the actual numbers presented in the Company's actual cost of service rate design testimony. [Base Power Supply Rate, $/kWh x PPFAC % Rate = Net Power Supply Rate, $/kWh]

to lower load factors and higher distribution losses, the Residential Service customers, due to summer cooling demand, utilize more expensive summer on-peak power on a weighted average basis relative to the Large Power Service customers, thus contributing to a higher cost per kWh on an annual basis.

As shown in Table 4 below, if we compare the marginal cost of fuel and purchased power to serve Residential Service and Large Power Service customers, we see that in 2015, the marginal cost of fuel and purchased power to serve the Residential Service class customers was $0.27013 per kWh, or 8.34% higher than the $0.024933 per kWh of marginal cost of fuel and purchased power to serve the Large Power Service class customers

Table 4 – UNSE Marginal Cost Comparison

Months	UNSE 2015 Marginal Costs $/kWh	Residential Service $/kWh	Large Power Service $/kWh
January	$0.025215	$0.025619	$0.025263
February	$0.023133	$0.023594	$0.023111
March	$0.022728	$0.023329	$0.022714
April	$0.022628	$0.023508	$0.022813
May	$0.022993	$0.024734	$0.023007
June	$0.027244	$0.029416	$0.027201
July	$0.029155	$0.032133	$0.029177
August	$0.030314	$0.033079	$0.030354
September	$0.027512	$0.029911	$0.027573
October	$0.024438	$0.024850	$0.024362
November	$0.021433	$0.021702	$0.021491
December	$0.020275	$0.020700	$0.020207
Annual	$0.024770	$0.027013	$0.024933

The Company believes that the proposed PPFAC percentage rate will provide more accurate and equitable price signals and improve the Company's overall rate design for customers. The PPFAC percentage rate results in an improved allocation of power supply costs by customer class based on the actual cost to serve these customer classes.

Q. Does this conclude your Testimony?

A. Yes, it does.

Exhibit MES-R-1

Load Factor - 37%

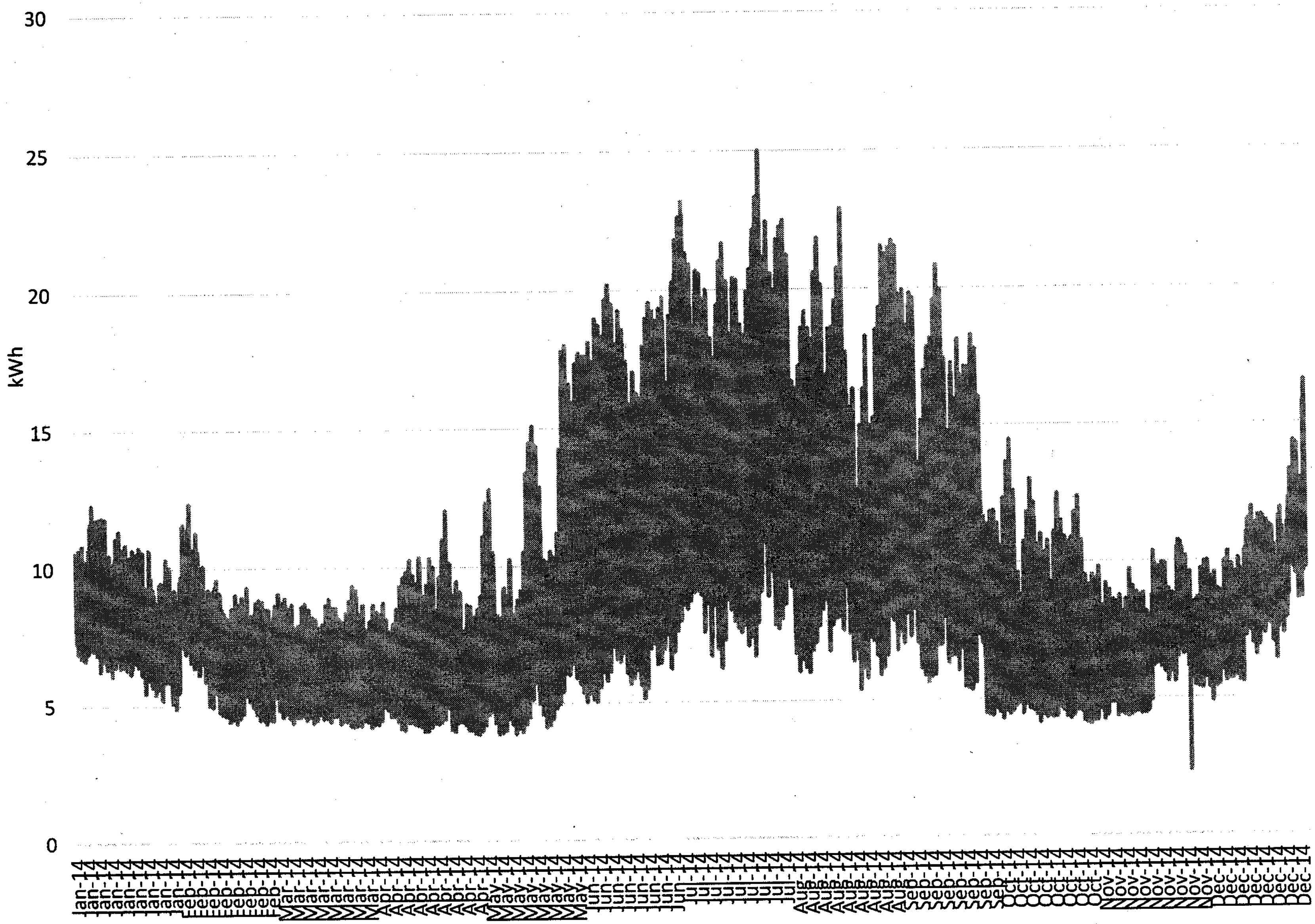
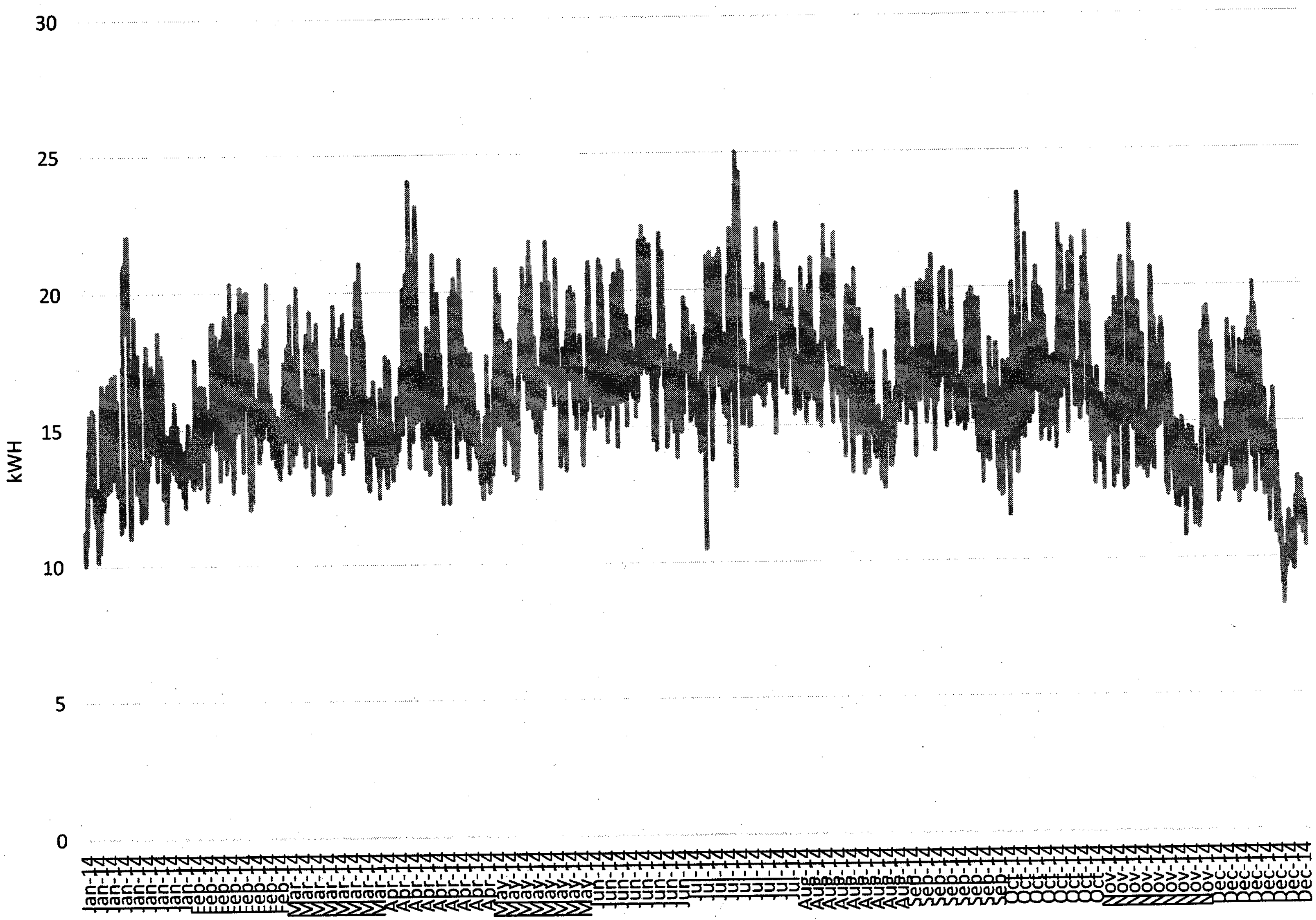


Exhibit MES-R-2

Load Factor - 65%



BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

Rejoinder Testimony of

Michael E. Sheehan

on Behalf of

UNS Electric, Inc.

February 29, 2016

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Exhibit

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Michael E. Sheehan and my business address is 88 East Broadway Blvd., Tucson, Arizona, 85701.

Q. Did you file Direct or Rebuttal Testimony in this proceeding?

A. Yes.

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

A. My testimony responds to Staff's surrebuttal witness Barbara Keene in regard to the base cost of fuel and purchased power and the proposed modifications to the Purchased Power and Fuel Adjustment Clause ("PPFAC").

II. BASE COST OF FUEL AND PURCHASED POWER

Q. What did Staff recommend in surrebuttal testimony regarding the base cost of fuel and purchased power for UNSE?

A. Staff recommended that UNSE update the base cost of fuel and purchased power prior to establishing new rates in this case based on Staff's methodology as proposed in Staff's direct testimony.

Q. Does the Company accept Staff's surrebuttal proposal in regard to the base cost of fuel and purchased power.

A. Yes. The Company believes that updating the base cost of fuel and purchased power just prior to establishing new rates in this case will provide UNSE customers with the most up to date estimate.

III. PROPOSED MODIFICATIONS TO THE PPFAC

Q. Did Staff recommend approving the Company's proposed Base Rate Annual Adjustment?

A. No, but Staff proposed an alternative.

Q. What was Staff's alternative proposal?

A. Staff recommends that the formula used for calculating the monthly PPFAC rate be modified to include consideration of the bank balance.

Q. Does the Company agree with Staff's alternative proposal?

A. Yes. The Company believes that the inclusion of the bank balance in the monthly PPFAC rate calculation provides for a more timely and equitable recovery[1] of the bank balance for both customers and the Company.

Q. Did Staff's surrebuttal address the Company's proposed modification of a PPFAC percentage rate adjustment?

A. No.

[1] Recovery means that in a scenario where the bank balance is over collected, UNSE customers would receive refunds on a more timely basis. Whereas, in the scenario where the bank balance is under collected, the Company would realize cost recovery on a more timely basis.

Q. Does the Company still support the concept of a PPFAC percentage rate adjustment?

A. Yes. The Company believes that a PPFAC percentage rate adjustment results in an improved allocation of power supply costs by customer class based on the actual cost to serve these customer classes.

Q. Please describe the Company's proposal to apply a PPFAC rate as a percentage of base fuel costs?

A. Each customer class rate schedule has a base power supply rate component. These base power supply rate components differ by customer class, by time of use and by season. Currently, the PPFAC rate is applied on a dollar per kWh basis equally across all customer classes and rate schedules and has no relationship to the customer's original base power supply rate. As a result, the Company is proposing to refund or collect the PPFAC as a percentage of each customer's class's underlying base power supply charge. An example of UNSE's proposed PPFAC rate percentage methodology is provided in Exhibit MES-J-1.

Q. Why is the Company's proposed PPFAC percentage rate an improvement over the current PPFAC rate calculation?

A. The PPFAC percentage rate results in an improved allocation of power supply costs by customer class based on the actual cost to serve these customer classes. In addition, the percentage rate applies changes to the PPFAC in a manner that better maintains the original cost of service allocations that are approved as part of a general rate case.

Q. Why is the PPFAC percentage rate more equitable by rate class?

A. If we compared the incremental cost of serving similarly sized Residential Service customers to that of Large Power Service customers[2], we would observe that Residential Service customers incur higher fuel and purchased power costs on a dollar per kWh basis than Large Power Service customers. This is based on the fact that Residential Service customers have a lower load factor that results in Residential Service customers utilizing a higher percentage of on-peak energy during the year and consuming a higher percentage of energy during the summer months relative to the usage of Large Power Service customers. In addition to these seasonal and time of use differences, Residential Service customers would also incur higher costs on a $/kWh basis associated with any fixed costs being spread over few kilowatt hours. Further, Large Power Service customers take delivery at a higher voltage level thus avoiding additional costs associated with distribution losses. The Company believes that the proposed PPFAC percentage rate will provide more accurate and equitable price signals resulting in an improved rate design for customers.

Q. Does this conclude your Testimony?

A. Yes, it does.

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[2] As shown on Page 4 of Exhibit MES-J-1, a comparison is made between 25 MW of new Residential Service customers and 25 MW of new Large Power Service customers. Page 5 highlights that Residential Service customers were estimated to cost 8.34% higher than Large Power Service customers on a marginal cost basis (energy only) based on 2015 estimates of UNSE system costs.

Exhibit MES-RJ-1

PPFAC % Rate Overview

- UNS Electric is proposing to modify the PPFAC to better allocate price increases/deceases by customer rate classes

- This change would utilize a PPFAC percentage rate rather than a straight $/kWh rate that is currently used today

- The PPFAC % rate provides for a more equitable treatment of price changes by rate class by allocating costs that mirror the cost of service rate design principles

- The following example details how this methodology would be applied comparing the impacts to a Residential Service customer with a low load factor to a Large Power Service customer with a high load factor.

PPFAC Rate (Current)

Test Year	KWh	Fuel Costs	$/kWh
Residential	826,362,520	45,732,487	$0.055342
Small Commercial	118,623,805	6,473,935	$0.054575
Commercial	562,295,292	30,492,916	$0.054229
Industrial/Mining	92,718,383	4,300,663	$0.046384
	1,600,000,000	87,000,000	$0.054375

Rate Change Assumptions	
Existing Base Power Supply, $/kWh	$0.054375
New Average Fuel Rate, $/kWh	$0.049531

PPFAC Rate, $/KWh	-$0.004844

PPFAC Rate $/kWh = Existing Base Power Supply, $/kWh / New Average Fuel Rate, $/kWh

PPFAC Rate $/kWh applied equally across all Rate Classes

Base Cost of Fuel and Purchase Power	Base Power Supply $/kWh	PPFAC Rate $/kWh	Net Power Supply $/kWh	Rate Impact %
Residental	$0.055342	-$0.004844	$0.050498	-8.75%
Small Commercial	$0.054575	-$0.004844	$0.049732	-8.88%
Commercial	$0.054229	-$0.004844	$0.049386	-8.93%
Industrial/Mining	$0.046384	-$0.004844	$0.041540	-10.44%
Aggregated Base Rate	$0.054375	-$0.004844	$0.049531	-8.91%

PPFAC Percentage Rate (Proposed)

Rate Change Assumptions	
Base Power Supply , $/kWh	$0.054375
New Average Power Supply, $/kWh	$0.049531

PPFAC, %	-8.908%

PPFAC % Rate = New Average Fuel Rate, $/kWh / (Existing Base Power Supply, $/kWh – 1)

PPFAC % applied equally across all Rate Classes

Base Cost of Fuel and Purchase Power	Base Power Suppy $/kWh	PPFAC % %	Net Power Supply $/kWh	Rate Impact $/kWh
Residental	$0.055342	-8.908%	$0.050412	-$0.004930
Small Commercial	$0.054575	-8.908%	$0.049714	-$0.004862
Commercial	$0.054229	-8.908%	$0.049399	-$0.004831
Industrial/Mining	$0.046384	-8.908%	$0.042252	-$0.004132
Aggregated Base Rate	$0.054375	-8.908%	$0.049531	-$0.004844

PPFAC % Rate Results

- PPFAC % Rate provides more equitable treatment of price changes by rate class
- PPFAC % Rate mirrors rate case cost of service rate design principles
- PPFAC % Rate allocates cost to reflect seasonal and hourly usage patterns
- Based on this example, the decrease in the PPFAC rate results in a bigger savings to residential customers

UNSE Customer Rate Class	Existing Base Power Supply Rate $/kWh	New Power Supply Rate $/kWh Current PPFAC Rate	New Power Supply Rate $/kWh Proposed PPFAC % Rate
Residential Service	$0.055342	$0.050498	$0.050412
Large Power Service	$0.046384	$0.041540	$0.042252

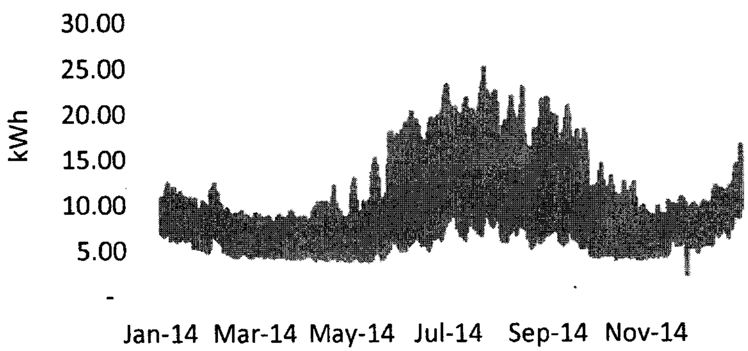
Residential Service vs. Large Power Service

Residential Service customers consume a higher percentage of on-peak and summer energy versus Large Power Service customers

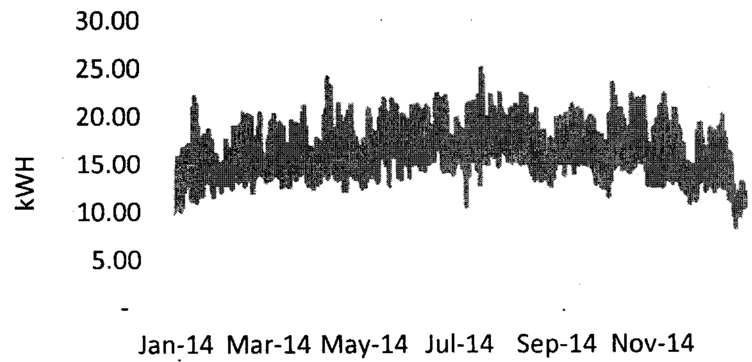
	Residential		Large Power Service	
TOU	Annual Usage, kWh	% of Annual	Annual Usage, kWh	% of Annual
On-Peak	568,517	75%	166,486	67%
Off-Peak	189,311	25%	83,485	33%
Total	757,828	100%	249,971	100%

Summer Usage	344,713	45%	89,279	36%

Residential Service - Load Factor - 37%



Large Power Service - Load Factor - 65%



Residential Service vs. Large Power Service

Low Load Factor Customers Incur

- Higher marginal costs (seasonal usage)
- Higher fixed system costs
  (spread over fewer kWh)
- Higher distribution losses

The PPFAC % Rate better allocates PPFAC changes based on the cost to serve a particular rate class

Marginal Cost by Rate Class

Months	UNSE 2015 Marginal Costs $/kWh	Residental Service $/kWh	Large Power Service $/kWh
January	$0.025215	$0.025619	$0.025263
February	$0.023133	$0.023594	$0.023111
March	$0.022728	$0.023329	$0.022714
April	$0.022628	$0.023508	$0.022813
May	$0.022993	$0.024734	$0.023007
June	$0.027244	$0.029416	$0.027201
July	$0.029155	$0.032133	$0.029177
August	$0.030314	$0.033079	$0.030354
September	$0.027512	$0.029911	$0.027573
October	$0.024438	$0.024850	$0.024362
November	$0.021433	$0.021702	$0.021491
December	$0.020275	$0.020700	$0.020207
Annual	$0.024770	$0.027013	$0.024933

Note: *The marginal costs represented in the table above only reflect the cost of energy and exclude any fixed costs such as firm capacity or transmission.*

Customer Bill Samples

- The following exhibits details how the customer bill would be modified under the PPFAC % rate methodology.

- The following customer rate classes are show below:
  - RES-01 Residential Service
  - LPS – Large Power Service

UniSourceEnergy SERVICES

#BWNMMYZ

Bill Due: 02-01-2016
Due Date: 02-15-2016

John Doe
2222 S 5th Street
Prescott AZ 86304-8073

RES-01 Residential Service

DELIVERY SERVICES	
Customer Charge	10.00
Customer Charge Acquisition Credit	1.15 CR
Delivery Charge 1st 400kWhs 400.00 @ $0.0193	7.72
Delivery Charge 401-1000 kWhs 600 @ $0.03435	20.62
Delivery Charge - Above 1,000 kWhs 288.00 @ $0.038499	11.09
Transmission Cost Adjustor-kWh 1,288.00 @ $0.00114	1.47
POWER SUPPLY CHARGES	
Base Power Supply Charge kWh 1,288.00 @ $0.055342	71.28
PPFAC - kWh 1,288.00 @ $-0.004844	**6.26 CR**
PPFAC Acquisition CR - kWh 1288.00 @ $-0.00098	1.26 CR
TOTAL DELIVERY & POWER SUPPLY CHARGES	113.52
GREEN ENERGY CHARGES	
Renewable Energy Standard Tariff	3.40
DSM Surcharge - kWh 1,288.00 @ $0.0015	1.93
LFCR EE 0.3058% of $113.52	0.35
LFCR DG 0.2746% of $113.52	0.31
TAXES AND ASSESSMENTS	
State Sales Tax	7.63
County Sales Tax	0.34
City Franchise Fee	2.66
RUCO Assessment	0.04
ACC Assessment	0.29
TOTAL CURRENT CHARGES - Electric Service	130.18

PPFAC Rate

UniSourceEnergy SERVICES

#BWNMMYZ

Bill Due: 02-01-2016
Due Date: 02-15-2016

John Doe
2222 S 5th Street
Prescott AZ 86304-8073

RES-01 Residential Service

DELIVERY SERVICES	
Customer Charge	10.00
Customer Charge Acquisition Credit	1.15 CR
Delivery Charge 1st 400kWhs 400.00 @ $0.0193	7.72
Delivery Charge 401-1000 kWhs 600 @ $0.03435	20.62
Delivery Charge - Above 1,000 kWhs 288.00 @ $0.038499	11.09
Transmission Cost Adjustor-kWh 1,288.00 @ $0.00114	1.47
POWER SUPPLY CHARGES	
Base Power Supply Charge kWh 1,288.00 @ $0.055342	71.28
PPFAC % @ - 8.91% of $71.28	**6.35 CR**
PPFAC Acquisition CR - kWh 1288.00 @ $-0.00098	1.26 CR
TOTAL DELIVERY & POWER SUPPLY CHARGES	113.41
GREEN ENERGY CHARGES	
Renewable Energy Standard Tariff	3.40
DSM Surcharge - kWh 1,288.00 @ $0.0015	1.93
LFCR EE 0.3058% of $113.41	0.35
LFCR DG 0.2746% of $113.41	0.31
TAXES AND ASSESSMENTS	
State Sales Tax	7.63
County Sales Tax	0.34
City Franchise Fee	2.66
RUCO Assessment	0.04
ACC Assessment	0.29
TOTAL CURRENT CHARGES - Electric Service	130.07

PPFAC % Rate

UniSourceEnergy SERVICES

#BWNMMYZ

Bill Due: 02-01-2016
Due Date: 02-15-2016

ABC Company
444 N Main Ave
Prescott AZ 86304-8073

LPS – Large Power Service

DELIVERY SERVICES	
Customer Charge	1,200.00
Customer Charge Acquisition Credit	143.78 CR
Demand Charge per kW 1,384 @22.00	30,448.00
Transmission Cost Adjustor per kW 1,384 @ $0.4329	599.13
Power Factor Adjustment	1,210.00
Delivery Charge 622,000.00 @ $0.000462	287.36
POWER SUPPLY CHARGES	
Base Power Supply Charge kWh 622,000.00 @ $0.046384	28,850.85
PPFAC - kWh 622,000.00.00 @ $-0.004844	**3012.97 CR**
PPFAC Acquisition CR - kWh 622,000.00 @ $-0.00098	609.56 CR
TOTAL DELIVERY & POWER SUPPLY CHARGES	58,829.03
GREEN ENERGY CHARGES	
Renewable Energy Standard Tariff	90.00
DSM Surcharge - kWh 622,000.00 @ $0.0015	933.00
LFCR EE 0.3058% of $58,829.03	179.89
LFCR DG 0.2746% of $58,829.03	161.54
TAXES AND ASSESSMENTS	
ACC Assessment	119.59
TOTAL CURRENT CHARGES - Electric Service	60,313.06

PPFAC Rate

UniSourceEnergy SERVICES

#BWNMMYZ

Bill Due: 02-01-2016
Due Date: 02-15-2016

ABC Company
444 N Main Ave
Prescott AZ 86304-8073

LPS – Large Power Service

DELIVERY SERVICES	
Customer Charge	1,200.00
Customer Charge Acquisition Credit	143.78 CR
Demand Charge per kW 1,384 @22.00	30,448.00
Transmission Cost Adjustor per kW 1,384 @ $0.4329	599.13
Power Factor Adjustment	1,210.00
Delivery Charge 622,000.00 @ $0.000462	287.36
POWER SUPPLY CHARGES	
Base Power Supply Charge kWh 622,000.00 @ $0.046384	28,850.85
PPFAC % @ - 8.91% of $28,850.85	**2570.61 CR**
PPFAC Acquisition CR - kWh 622,000.00 @ $-0.00098	609.56 CR
TOTAL DELIVERY & POWER SUPPLY CHARGES	59,271.39
GREEN ENERGY CHARGES	
Renewable Energy Standard Tariff	90.00
DSM Surcharge – kWh 622,000.00 @ $0.0015	933.00
LFCR EE 0.3058% of $59,271.39	181.25
LFCR DG 0.2746% of $59,271.39	162.76
TAXES AND ASSESSMENTS	
ACC Assessment	119.59
TOTAL CURRENT CHARGES - Electric Service	60,757.99

PPFAC % Rate

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 FOR RELATED APPROVALS.	DOCKET NO. E-04204A-15-______

UNSE-19
ADMITTED

Direct Testimony of

Denise A. Smith

on Behalf of

UNS Electric, Inc.

May 5, 2015

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Denise Smith. My business address is 88 East Broadway Blvd., Tucson, Arizona 85701.

Q. What is your position with UNS Electric, Inc. ("UNS Electric" or the "Company")?

A. I am employed by Tucson Electric Power Company ("TEP"), a wholly-owned subsidiary of UNS Energy Corporation ("UNS Energy"). I am the Director of Customer Service & Programs for all the regulated subsidiaries of UNS Energy, including TEP, UNS Electric, Inc. ("UNS Electric" or the "Company") and UNS Gas, Inc.

Q. Please describe your education and experience.

A. I graduated from Northern Arizona University ("NAU") earning a Bachelor of Science degree in Mathematics with an extended major in Statistics, and then completed graduate work in Statistics at NAU. After leaving NAU, I was hired by Pima Association of Governments in the Travel Reduction Program, which reduces vehicle emissions by targeting major employers to reduce employees' travel to and from work. During my tenure at TEP, I completed a Masters of Business Administration at the University of Phoenix.

I was hired in 1996 by TEP as a Demand-Side Management ("DSM") Analyst, developing, analyzing and researching new DSM and energy-related market programs. In 1999, I moved into the Pricing and Rates Department, where I developed cost-of-service and revenue requirement models. In 2002, I was promoted to the Director of the Pricing and Rates Department. In 2008, I accepted the position of Director of Conservation and Renewable Programs. Most recently, in 2013, I took over as the Director of Customer

Service and Programs, including energy efficiency and other customer programs as well as the call center, billing services, payments, and credit and collections.

Q. What is the purpose of your Direct Testimony?

A. I provide an overview of the Company's improvements to Customer Service since the last rate case and discuss proposed changes to UNS Electric's Rules and Regulations ("Rules").

II. CUSTOMER SERVICE.

Q. What improvements have been made to Customer Service since the last rate case?

A. In 2013, the Company completed technology upgrades to enhance Customer Service. The first update was to the customer Interactive Voice Response (IVR) software which increased the number of self-service options for customers. Customers can now hear billing information such as outstanding balance and due date as well as ask for payment extensions. The Company also upgraded the call-back system so that a customer can elect to receive a return phone call from a Customer Service Representative rather than waiting on hold. The new call-back system holds a customer's place in line and places the Customer Service Representative on the call before dialing the customer.

The Company also has enhanced its communications with customers during power outages by proactively informing them of the restoration progress through automated call-backs and social media. The Company is also developing an interactive outage map that will be accessible from any desktop computer or mobile device. In the case of major outages, a dedicated phone line will be set up to give customers tailored information on the outage restoration progress and Company representatives may be available on-site.

As a result of overall customer service improvements, the number of customer complaints filed with the Commission over the last three (3) years has decreased by more than 33% from 56 in 2011 to 37 in 2014. We will continue to focus on improving Customer Service, better serving our customers and further reducing the number of customer complaints.

III. PROPOSED MODIFICATIONS OF RULES AND REGULATIONS.

Q. Why is UNS Electric proposing changes to its Rules?

A. UNS Electric is proposing modifications to its Rules to update provisions to meet current operational needs, better align them with our customers' needs and ultimately provide better customer service. Many of UNS Electric's current Rules were derived from the Arizona Administrative Code ("Code") which was adopted in 1982, more than 30 years ago. The most recent changes to the Code were made in the 1990s. Since that time there have been a number of societal and technological changes that necessitate updating the Rules to align with current business practices. In addition, some of the proposed revisions are intended to clarify and reorganize certain provisions of the Rules to make them easier to read and understand and to reduce potential confusion. The clean version of the Rules is attached as **Exhibit DAS-1**. The redlined changes to the Rules are attached as **Exhibit DAS-2**.

Q. Will you be describing all of the proposed Rule changes redlined in Exhibit DAS-2?

A. No. We consider many of the changes to be non-substantive and are intended to clean-up and clarify language in the Rules. Therefore, I am addressing those changes we consider to be more substantive.

Q. Why is UNS Electric proposing changes to Section 3, entitled "Establishment of Service"?

A. As Director of Customer Service, I am in a position of having day-to-day interaction with our customers. When customers call needing assistance to pay their bills, we offer them a number of options including due date extensions, payment plans or, if qualified, information about the limited-income assistance programs. Despite our best efforts to work with customers, the Company's bad debt expense has increased and those costs are ultimately passed through to other UNS Electric customers. Modifications to the Company's ability to require deposits and to retain deposits until customers demonstrate credit worthiness are fair and reasonable and in the best interest of UNS Electric and its customers.

Q. Please describe the modifications UNS Electric is proposing regarding the establishment and refund of customer deposits (Subsection 3.B).

A. <u>Establishment or Reestablishment of Deposits</u>

As a way to mitigate bad debt, the Company currently has the ability – in certain circumstances - to require a customer to establish or reestablish a deposit if the customer's bill is delinquent three or more times over a 12 month period. Or put another way, the Company cannot require a deposit unless the customer's account is delinquent three months in a row or one out of every four months over the course of a year, which is unreasonably lenient.

We believe it would be more fair and reasonable if UNS Electric had the ability to require a deposit when a customer's bill was delinquent two or more times over a 12 month period. In addition, the Company should be able to require a deposit if, in the last 12 months, a residential customer has filed bankruptcy or a non-residential customer's financial condition may jeopardize payment of their bill. We believe these modifications would encourage customers to remain current on their bills, protect customers from building up large unpaid balances and help the Company recover past due balances. It also could help avoid situations such as the Company's recent experience of having one of its largest customers file bankruptcy, leaving UNS Electric with unpaid bills totaling $1.2 million.

<u>Expiration or Refund of Deposits</u>

Currently, deposits from residential customers automatically expire or are returned if, after 12 months, the customer has not been delinquent more than two times - even if the customer has been disconnected for non-payment during this period. This too is overly lenient. The Company proposes to modify this requirement to allow it to retain the deposit if the residential customer has been delinquent two times over this 12 month period. Retaining a deposit until a customer demonstrates credit worthiness for 12 consecutive months is fair and reasonable. A bill isn't considered delinquent until 26 days, nearly one month, after the bill date, which gives customers a considerable amount of time to make their payment and remain in good financial standing with the Company. UNS Electric also proposes to be able to retain the deposit if the residential customer has been disconnected for non-payment or has filed bankruptcy within this 12 consecutive month period, which is consistent with Arizona Public Service Company's (APS) Commission-approved Rules.

The Company is also proposing modifications to the refund requirements for non-residential customers. Currently, deposits from non-residential customers automatically expire or are returned after 24 consecutive months if the customer was delinquent three times or disconnected for non-payment during the most recent 12 month period. The Company is proposing to modify this requirement to automatically expire or return the non-residential customer deposit after 24 months *except when* the customer: i) was delinquent two times, ii) has been disconnected for non-payment during the most recent

12 month period, or iii) the customer's financial condition may jeopardize payment of their bill.

Q. Please describe the specific changes to Section 3, entitled "Establishment of Service"?

A. Subsection 3.B.2 was deleted as the payment of a deposit is reflected on a customer's billing statement. The deletion of 3.B.2 has caused the subsequent Subsections to be renumbered.

Language has been added to Subsection 3.D.1 and Subsection 3.D.11 to address circumstances where an applicant for service has an affiliate with common ownership that has a delinquent balance from a prior account.

In Subsection 3.I.4, the phrase "or other person benefitting from the service" has been clarified because there are times when there is no customer of record and the occupant or landlord is the responsible party.

Language was added under Subsection 3.J 'Access' to include other purposes where the Company would need access to a customer's premises.

Subsection 3.K has been added regarding customer-specific information. This language is consistent with the A.A.C. R14-2-203.A.2. Moreover, the section now provides how the customer authorization may be obtained.

Q. Please describe the changes to Section 4, entitled 'Minimum Customer Information Requirements'.

A. In Subsection 4.A.6, the Company proposes a modification allowing it to charge the customer a fee for consumption history requests. The Commission has approved this charge for TEP.

Q. Please describe the changes to Section 6, entitled 'Service Lines and Establishments'.

A. Subsection 6.A.8 was deleted because the description of the fee was not up-to-date and the fee is defined in Subsection 3.E.3.

Subsection 6.B.2.a has been slightly revised to correct an oversight that occurred when line extension changes were approved in UNS Electric's last rate case. "150 feet and no more than one carryover pole, if required" has been changed to "550 feet" - which is consistent with Section 7.

In Subsection 6.F, clarifying language has been added to fully explain the charge for temporary service.

Subsection 6.G has been proposed to provide a Rule for when the Company discovers that a customer's privately owned underground service cable has failed. This new language simply defines the Company's current practice.

Q. Please describe the changes to Section 7, entitled 'Line Extensions'.

A. Language included in Subsection 7.B.1 was simplified to eliminate customer confusion.

Language was added to Subsection 7.C.9.g to keep the Rule consistent with TEP's Commission-approved Subsection 7.C.7.g. This new language simply defines the Company's current practice.

Changes were made to Subsection 7.D, tax gross-ups. The changes are to provide additional clarity in how the Rules are to be applied. In addition, section 7.D.4.a has been added for advances in aid of construction, which is similar to 7.D.3.a for contributions in aid of construction.

Q. Please describe the changes to Section 8, entitled 'Provision of Service'.

A. In Subsection 8.B.4, the Company proposes deleting the language, "regardless of who owns the meter", because the Company always owns the meter.

Q. Please describe the changes to Section 10, entitled 'Meter Reading'.

A. Subsection 10.B.4 was deleted because we do not have meters that contain charts any longer.

A new Subsection 10.B.4 was added regarding the use of digital meters. The industry is moving towards replacing analog meters with digital meters that can be read remotely over a fixed network. UNS Electric's Meter Data Management System (MDM) permits the Company to read meters remotely by using interval data. Our system can bill based on a summation of the interval data instead of separate register reads, providing cost savings to customers in more expensive meters that can create these register reads. This will also save money and labor when rates change and the meters do not need to be reprogrammed at each individual service.

Subsection 10.H has been inserted to reference the Automated Meter Opt-Out program and the charges associated with the program.

Q. Please describe the changes to Section 11, entitled 'Billing and Collection'.

A. Subsection 11.A.3.e was added to describe another example of when the Company may need to estimate a bill.

In Subsection 11.A.7, "one month" was changed to "two months" in order to be consistent with Subsection 11.A.4.

In Subsection 11.B.2.k, we added "Other ACC-approved charges", which are listed on the customer's bill.

In Subsection 11.F.3.b, we added another example of when we would be able to back bill to the date service was established.

In Subsection 11.H, we added clarifying language to our Budget Billing program.

In Subsection 11.I.2.c, we reduced the number of monthly installments from six (6) months to three (3) months because it is the same period allowed for corrected charges for residential under billings.

In Subsection 11.J.3, we added language to include property owners in the case of a known landlord/tenant situation.

Q. Please describe changes to Section 12 – "Termination of Service".

A. UNS Electric proposes to add a new Subsection 12.H which describes situations where the Company may install a load-limiting meter in lieu of disconnecting service for non-payment of customers who have accumulated debt equivalent to a three (3) month bill and who have a medical alert designation.

Q. Does this conclude your Direct Testimony?

A. Yes.

Exhibit DAS-1

CLEAN

TABLE OF CONTENTS

SECTION 1
APPLICABILITY OF RULES AND REGULATIONS AND DESCRIPTION OF SERVICE

A. UNS Electric, Inc. ("Company") is an electric utility operating within portions of the state of Arizona. The Company will provide service to any person, institution or business located within its service area in accordance with the provisions of its Rates and the terms and conditions of these Rules and Regulations.

B. All electricity delivered to any Customer is for the sole use of that Customer on that Customer's premises only. Electricity delivered by the Company will not be redelivered or resold, or the use thereof by others permitted unless otherwise expressly agreed to in writing by the Company. However, those Customers purchasing electricity for redistribution to the Customer's own tenants (only on the Customer's premises) may separately meter each tenant distribution point for the purpose of prorating the Customer's actual purchase price of electricity delivered among the various tenants on a per unit basis.

C. These Rules and Regulations will apply to all electricity service furnished by the Company to its Customers.

D. These Rules and Regulations are part of the Company's Rates on file with, and duly approved by, the Arizona Corporation Commission. These Rules and Regulations will remain in effect until modified, amended, or deleted by order of the ACC. No employee, agent or representative of the Company is authorized to modify the Company rules.

E. These Rules and Regulations will be applied uniformly to all similarly situated Customers.

F. In case of any conflict between these Rules and Regulations and the Arizona Corporation Commission's rules, these Rules and Regulations will apply.

G. Whenever the Company and an Applicant or a Customer are unable to agree on the terms and conditions under which the Applicant or Customer is to be served, or are unable to agree on the proper interpretation of these Rules and Regulations, either party may request assistance from the Consumer Services Section of the Utilities Division of the ACC. The Applicant or Customer also has the option to file an application with the ACC for a proper order, after notice and hearing.

H. The Company's supplying electric service to the Customer and the acceptance thereof by the Customer will be deemed to constitute an agreement by and between the Company and the Customer for delivery, acceptance of and payment for electric service under the Company's Rules and Regulations and applicable Rates.

SECTION 2
DEFINITIONS

A. In these Rules and Regulations, the following definitions will apply unless the context requires otherwise:

1. Actual Cost: The cost incurred by the Company for labor, materials and equipment including the cost of overheads.

2. Advance in Aid of Construction ("Advance"): Funds provided to the utility by the Applicant under the terms of a line extension agreement, the value of which may be refunded.

3. Applicant: A person requesting the Company to supply electric service.

4. Application: A request to the Company for electric service, as distinguished from an inquiry as to the availability or charges for such service.

5. Arizona Corporation Commission ("ACC" or "Commission"): The regulatory authority of the State of Arizona having jurisdiction over public service corporations operating in Arizona.

6. Billing Month: The period between any two (2) regular readings of the Company's meters at approximately thirty (30) day intervals.

7. Billing Period: The time interval between two (2) consecutive meter readings that are taken for billing purposes.

8. Company: UNS Electric, Inc. acting through its duly authorized officers or employees within the scope of their respective duties.

9. Contiguous Site: A single site not separated by private or public property, or public street, or right of way and operated as one integral unit under the same name and as a part of the same business.

10. Contributions in Aid of Construction ("Contribution"): Funds provided to the Company by the Applicant under the terms of a line extension agreement and/or service connections tariff, the value of which is not refundable.

11. Curtailment Priority: The order in which electric service is to be curtailed to various classifications of Customers, as set forth in the Company's filed Rates.

12. Customer: The person(s) or entity(ies) in whose name service is rendered, as evidenced by the request for electric service by the Applicant(s), or by the receipt and/or payment of bills regularly issued in the Customer's name regardless of the identity of the actual user of the service.

13. Customer Charge: The amount the Customer must pay the Company for the availability of electric service, excluding any electricity used, as specified in the Company's Rates.

14. Day: Calendar day.

SECTION 2
DEFINITIONS
(continued)

15. Demand: The rate at which power is delivered during any specified period of time. Demand may be expressed in kilowatts, kilovolt-amperes, or other suitable units.

16. Developer: One or more natural or artificial entities that own, improve, or remodel real estate.

17. Distribution Lines: The Company lines operated at distribution voltage, which are constructed along public roadways or other bona fide rights-of-way, including easements on Customer's property.

18. Electronic Billing: Optional billing service whereby Customers may elect to receive, view and pay their bills electronically.

19. Energy: Electric energy, expressed in kilowatt-hours.

20. Illness: A medical ailment or sickness for which a residential Customer obtains a verified document from a licensed medical physician stating the nature of the illness and that discontinuance of service would be especially dangerous to the Customer's health.

21. Interruptible Electric Service: Electric service that is subject to interruption as specified in the Company's Rate.

22. Kilowatt ("kW"): A unit of power equal to 1,000 watts.

23. Kilowatt-hour ("kWh"): Electric energy equivalent to the amount of electric energy delivered in one hour when delivery is at a constant rate of one (1) kilowatt.

24. Law: Any statute, rule, order or requirement established and enforced by government authorities.

25. Line Extension: The lines and equipment necessary to extend the electric distribution system of the Company to provide service to additional Customers.

26. Master Meter: A meter for measuring or recording the flow of electricity that has passed through it at a single location where said electricity is distributed to tenants or occupants for their usage.

27. Megawatt ("MW"): A unit of power equal to 1,000,000 watts.

28. Meter: The instrument for measuring and indicating or recording the flow of electricity that has passed through it.

29. Meter Tampering: A situation where a meter has been illegally altered. Common examples are meter bypassing, use of magnets to slow the meter recording, and broken meter seals.

30. Minimum Charge: The amount the Customer must pay for the availability of electric service, including an amount of usage, as specified in the Company's Rates.

SECTION 2
DEFINITIONS
(continued)

31. Month: The period between any two (2) regular readings of the Company's meters at approximately thirty (30) day intervals.

32. On-Site Generation: Any and all power production generated on or adjacent to a Customer's property that is controlled, utilized, sold, or consumed by that Customer or its agent.

33. Permanent Customer: A Customer who is a tenant or owner of a service location who applies for and receives permanent electric service.

34. Permanent Service: Service which, in the opinion of the Company, is of a permanent and established character. The use of electricity may be continuous, intermittent, or seasonal in nature.

35. Person: Any individual, partnership, corporation, governmental agency, or other organization operating as a single entity.

36. Point of Delivery: In all cases, unless otherwise specified, "point of delivery" is the location on the Customer's building, structure, or premises where all wires, conductors, or other current-carrying devices of the Customer join or connect with wires, conductors, or other current-carrying devices of the Company. The Company will determine the point of delivery in accordance and based on the specific design specifications, relevant and appropriate technical standards and specifications, Rates and construction standards as applicable to the specific situation. Location and type of metering facilities will be determined by the Company and may or may not be at the same location as the point of delivery.

37. Power: The rate of generating, transferring and/or using electric energy, usually expressed in kilowatts.

38. Power Factor: The ratio of real or active power ("kW") to apparent or reactive power ("kVA").

39. Premises: All of the real property and apparatus employed in a single enterprise on an integral parcel of land undivided by public streets, alleys or railways.

40. Primary Service and Metering: Service supplied directly from the Company's high voltage distribution or transmission lines without prior transformation to a secondary level.

41. Prorate: To divide, distribute, or assess proportionately.

42. Rates: The charge(s), related term(s) and conditions of the Company's Tariffs.

43. Residential Subdivision: Any tract of land which has been divided into four or more contiguous lots with an average size of one acre or less for use for the construction of residential buildings or permanent mobile homes for either single or multiple occupancy.

SECTION 2
DEFINITIONS
(continued)

44. Residential Use: Service to Customers using electricity for domestic purposes such as space heating, air conditioning, water heating, cooking, clothes drying, and other residential uses and includes use in apartment buildings, mobile home parks, and other multiunit residential buildings.

45. Revenue: Delivery charge, power supply charge, demand charge, and PPFAC charge collected from Customer.

46. Rules and Regulations or Company Rules: These Rules and Regulations, which are a part of the Company's Tariffs and Rates.

47. Secondary Service: Service supplied at secondary voltage levels from the load side of step-down transformers connected to the Company's high voltage distribution lines.

48. Service Area: The territory in which the Company has been granted a certificate of convenience and necessity and is authorized by the ACC to provide electric service.

49. Service Drop: The overhead service conductors from the last Company-owned pole or other aerial support to and including the splices, if any, connecting to the Customer's service entrance conductors at a building or other structure.

50. Service Establishment Charge: The charge as specified in the Company's Rates, which covers the cost of establishing a new account.

51. Service Line: The line extending from a distribution line or transformer to the Customer's premises or point of delivery.

52. Service Reconnection Charge: The charge as specified in the Company's Rates which must be paid by the Customer prior to reestablishment of electric service each time the electricity is disconnected for nonpayment or whenever service is discontinued for failure otherwise to comply with the Company's Rates or Rules.

53. Service Reestablishment Charge: A charge as specified in the Company's Rates for service in the same location where the same Customer had ordered a service disconnection within the preceding twelve (12) month period.

54. Single Family Dwelling: A house, an apartment, or a mobile home permanently affixed to a lot, or other permanent residential unit which is used as a permanent home.

55. Single-Phase Service: Two (2) or Three (3) wire service.

56. Tariffs: The terms and conditions of the services offered by the Company, including a schedule of the Rates and charges for those services.

SECTION 2
DEFINITIONS
(continued)

57. Temporary Service: Service to premises or enterprises which are temporary in character, or where it is known in advance that the service will be of limited duration. Service which, in the opinion of the Company, is for operations of a speculative character is also considered temporary service.

58. Three-Phase Service: Four (4) wire service.

59. Weather Especially Dangerous to Health: That period of time commencing with the scheduled termination date when the local weather forecast, as predicted by the National Oceanographic and Administration Service, indicates that the temperature will not exceed thirty-two (32) degrees Fahrenheit for the next day's forecast. The ACC may determine that other weather conditions are especially dangerous to health as the need arises.

SECTION 3
ESTABLISHMENT OF SERVICE

A. Information from New Applicants

1. The Company may obtain the following minimum information from each application for service:

   a. Name or names of Applicant(s);

   b. Service address or location and telephone number;

   c. Billing address/telephone number, if different than service address;

   d. Social Security Number or Driver's License number and date of birth to be consistent with verifiable information on legal identification;

   e. Address where service was provided previously;

   f. Date Applicant will be ready for service;

   g. Statement of whether premises have been supplied with electric service previously;

   h. Purpose for which service is to be used;

   i. Statement of whether Applicant is owner or tenant of or agent for the premises;

   j. Information concerning the energy and demand requirements of the Customer; and

   k. Type and kind of life-support equipment, if any, used by the Customer or at the service address.

2. Where service is requested by two (2) or more individuals, the Company will have the right to collect the full amount owed to the Company from any one of the Applicants.

3. The supplying of electric service by the Company and the Customer's acceptance of that electric service will be deemed to constitute an agreement by and between the Company and the Customer for delivery, acceptance of and payment for electric service under the Company's applicable Rates, and Rules and Regulations.

4. The term of any agreement not otherwise specified will become operative on the day the Customer's installation is connected to the Company's facilities for the purpose of taking electric energy.

5. The Company may require a written contract with special guarantees from Applicants whose unusual characteristics of load or location would require excessive investment in facilities or whose requirements for service are of a special nature.

6. Signed contracts may be required for service to commercial and industrial establishments. No contract or any modification of the contract will be binding upon the Company until executed by a duly authorized representative of the Company.

7. Where an occupant of the premises who owes a debt to the Company, but is not the Applicant or the Customer, the occupant shall also be jointly and severally liable for the bills rendered to the premises.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

B. Deposits

1. The Company may require from any present or prospective Customer a deposit to guarantee payment of all bills. This deposit may be retained by the Company until service is discontinued and all bills have been paid; except as provided in Subsection B.3. below. Upon proper application by the Customer, the Company will then return said deposit, together with any unpaid interest accrued thereon from the date of commencement of service or the date of making the deposit, whichever is later. The Company will be entitled to apply said deposit together with any unpaid interest accrued thereon, to any indebtedness for the same class of service owed to the Company for electric service furnished to the Customer making the deposit. When said deposit has been applied to any such indebtedness, the Customer's electric service may be discontinued until all such indebtedness of the Customer is paid and a like deposit is again made with the Company by the Customer. No interest will accrue on any deposit after discontinuance of the service to which the deposit relates.

   The Company will not require a deposit from a new Applicant for residential service if the Applicant is able to meet any of the following requirements:

   a. The Applicant has had service of a comparable nature with the Company within the past two (2) years and was not delinquent in payment twice during the last twelve (12) consecutive months of service or was not disconnected for nonpayment; or

   b. The Applicant can produce a letter of credit or verification from an electric utility where service of a comparable nature was last received by Applicant, which states Applicant had a timely payment history at time of service discontinuation; or

   c. Instead of a deposit, the Company receives deposit guarantee notification from a social or governmental agency acceptable to the Company. A surety bond may be provided as security for the Company in an amount equal to the required deposit.

2. Cash deposits held by the Company twelve (12) months or longer will earn interest at the established one-year Treasury Constant Maturities rate, effective on the first business day of each year, as published in the Federal Reserve website.

3. Residential Customers – The Company may require a residential Customer to establish or reestablish a deposit if the Customer becomes delinquent in the payment of two (2) or more bills or has been disconnected from service during the last twelve (12) months.

   Deposits or other instruments of credit will automatically expire or be refunded or credited to the Customer's account after twelve (12) consecutive months of service during which time the Customer has not been delinquent two (2) times or has not been disconnected for non-payment, unless the Customer has filed bankruptcy in the last twelve (12) months.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

4. Non-Residential Customers – The Company may require a non-residential Customer to establish or reestablish a deposit if the Customer becomes delinquent in the payment of two (2) bills or if the Customer has been disconnected for non-payment during the last twelve (12) months, or when the Customer's financial condition may jeopardize the payment of their bill.

   Deposits and non-cash deposits on file with the Company will be reviewed after twenty-four (24) consecutive months of service and will be returned provided the Customer has not been delinquent two (2) times or disconnected for non-payment in the most recent twelve (12) month period, unless the Customer's financial condition warrants extension of the deposit.

5. The Company may review the Customer's usage after service has been connected and adjust the deposit amount based upon the Customer's actual usage.

6. A separate deposit may be required for each meter installed.

7. Residential Customer deposits will not exceed two (2) times that Customer's estimated average monthly bill. Non-residential Customer deposits will not exceed two and one-half (2.5) times that Customer's maximum estimated monthly bill. If actual usage history is available, then that usage, adjusted for normal weather, will be the basis for the estimate.

8. The posting of a deposit will not preclude the Company from terminating service when the termination is due to the Customer's failure to perform any obligation under the agreement for service or any of these Rules and Regulations.

C. Conditions for Supplying Service

The Company reserves the right to determine the conditions under which service will be provided. Conditions for service and extending service to the Customer will be based upon the following:

1. Customer has wired his premises in accordance with the National Electric Code, City, County and/or State codes, whichever are applicable.

2. If the Company determines that there is a reasonable basis to believe that the Customer's premises poses a safety risk to Company employees, then the Company may, at its option, install a meter or facilities with remote connect and/or disconnect capabilities.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

3. Customer has installed the meter loop in a suitable location approved by the Company.

4. In the case of a mobile home, the meter loop must be attached to a meter pole or to an approved support.

5. In case of temporary construction service, the meter loop must be attached to an approved support.

6. All meter loop installations must be in accordance with the Company's specifications and located at an outdoor location accessible to the Company.

7. Individual Customers may be required to have their property corner pins and/or markers installed to establish proper right-of-way locations.

8. Developers must have all property corner pins and/or markers installed necessary to establish proper locations to supply electric service to individual lots within subdivisions.

9. Where the installation requires more than one meter for service to the premises, each meter panel must be permanently marked (not painted) by the contractor or Customer to properly identify the portion of the premises being served.

10. The identification will be the same as the apartment, office, etc., served by that meter socket. The identifying marking placed on each meter panel will be impressed into or raised from a tab of aluminum, brass or other approved non-ferrous metal with minimum one-fourth (1/4) inch-high letters. This tag must be riveted to the meter panel. The impression must be deep enough to prevent the identification(s) from being obscured by subsequent painting of the building and attached service equipment.

11. The Company may require the assistance of the Customer and/or the Customer's contractor to open the apartments or offices at the time the meters are set, in order to verify that each meter socket actually serves the apartment or office indicated by the marking tag. In the case of multiple buildings the building or unit number and street address will be identified on the pull section in the manner described above.

D. Grounds for Refusal of Service

The Company may refuse to establish service if any of the following conditions exist:

1. When the Applicant or affiliate of the Applicant with common ownership has an outstanding amount due for the same class of electric service with the Company and the Applicant is unwilling to make arrangements with the Company for payment, in such cases, the Company shall be entitled to transfer the balance due or credit owed on the terminated service to any other active account of the Customer for the same class of service. The failure of the Customer to pay the active account shall result in the suspension or termination of service.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

2. A condition exists which, in the Company's judgment, is unsafe or hazardous to the Applicant, the general population, or the Company's personnel or facilities;

3. The Applicant refuses to provide the Company with a deposit when the Customer has failed to meet the credit criteria for waiver of deposit requirements;

4. Customer is known to be in violation of the Company's Rates or Rules and Regulations;

5. Customer fails to furnish the funds, service, equipment, and/or rights-of-way necessary to serve the Customer and which have been specified by the Company as a condition for providing service;

6. Customer fails to provide safe access to the meter that would be serving the Customer;

7. Applicant falsifies his or her identity for the purpose of obtaining service;

8. Service is requested by an Applicant and a prior Customer, who is either living with the Applicant, or who is an occupant of the premises who owes a debt to the Company from the same class of service from the same or a prior service address;

9. The Applicant is acting as an agent for a prior Customer who is deriving benefits from the energy supplied and who owes a delinquent bill from the same class of service from the same or a prior service address;

10. There is evidence of tampering or energy diversion.

11. Where the Company has a reasonable belief that the Applicant has common ownership with an affiliate that owes a delinquent bill for the same class of service.

E. Service Establishment, Reestablishment or Reconnection Charge

1. The Company will make a charge, as approved by the ACC, for service transfer for meter reads only set forth as Fee No. 1 in the UNS Electric Statement of Charges.

2. The Company may make a charge, as approved by the ACC, for the establishment, reestablishment, or reconnection of service. The charge for establishment, reestablishment or reconnection of service during regular business hours is set forth as Fee No. 4 in the UNS Electric Statement of Charges.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

3. Should service be established, reestablished or reconnected during a period other than the Company's regular business hours, at the Customer's request, the Customer may be required to pay an after-hour charge for the service connection set forth as Fee No. 5 in the UNS Electric Statement of Charges. Where the Company's scheduling will not permit service establishment, reestablishment or reconnection of service on the same day as requested, the Customer can elect to pay the after-hour charge for establishment that day, or service will be established on the next available business day. Even so, a Customer's request to have the Company establish service after-hours is subject to the Company having Staff available; there is no guarantee that the Company will have the staffing available for service establishment, reestablishment or reconnection of service outside of regular business hours.

4. For the purpose of this Rule, the definition of service establishment is where the Customer's facilities are ready and acceptable to the Company, the Applicant has obtained all required permits and/or inspections indicating that the Applicant's facilities comply with local construction safety and governmental standards and regulations, and the Company needs only to install a meter, read a meter, or turn the service on.

5. Service Reconnection Charge

   Whenever the Company has discontinued service under its usual operating procedures because of any default by the Customer as provided herein, a reconnection charge, not to exceed the charge for the reestablishment of service as set forth as Fee Nos. 4-5 in the UNS Electric Statement of Charges, shall be made and may be collected by the Company before service is restored. When, due to the behavior of the Customer, it has been necessary to discontinue service utilizing other than usual operating procedures, the Company shall be entitled to charge Fee No. 6 to restore service, as set forth in the UNS Electric Statement of Charges.

F. Temporary Service

1. Applicants for temporary service may be required to pay Line Extension charges in accordance with Section 7.C.9.d.

2. Where the duration of service is to be less than one (1) month, the Applicant will also be required to advance a sum of money equal to the estimated bill for service.

3. Where the duration of service is to exceed one (1) month, the Applicant may also be required to meet the deposit requirements of the Company, as outlined in Subsection B.1. above.

4. If at any time during the term of the agreement for service the character of a temporary Customer's operations changes so that, in the opinion of the Company, the Customer is classified as permanent, the terms of the Company's Line Extension rules will apply.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

G. Identification of Load and Premises

Upon request of the Company, the electric load and premises to be served by the Company must be clearly identified by the Customer at the time of application. If the service address is not recognized in terms of commonly used identification system, the Customer may be required to provide specific written directions and/or legal descriptions before the Company will be required to act upon a request for electric service.

H. Identification of Responsible Party

Any person applying on behalf of another Customer for service to be connected in the name of or in care of another Customer must furnish to the Company written approval from that Customer guaranteeing payment of all bills under the account. The Customer is responsible in all cases for service supplied to the premises until the Company has received proper notice of the effective date of any change. The Customer shall also promptly notify the Company of any change in physical or electronic billing address.

I. Tampering With or Damaging Company Equipment

1. The Customer agrees, when accepting service, that no one except authorized Company employees or agents of the Company will be allowed to remove or replace any Company owned equipment installed on Customer's property.

2. No person, except an employee or agent acting on behalf of the Company shall alter, remove or make any connection to the Company's meter or service equipment.

3. No meter seal may be broken or removed by anyone other than an employee or agent acting on behalf of the Company; however, the Company may give its prior consent to break the seal by an approved electrician employed by a Customer when deemed necessary by the Company.

4. The Customer will be held responsible for any broken seals, tampering, or interfering with the Company's meter(s) or any other Company owned equipment installed on the Customer's premises. In cases of tampering with meter installations, interfering with the proper working thereof, or any tampering, interfering, theft, or service diversion, including the falsification of Customer read-meter readings, Customer will be subject to immediate discontinuance of service. The Company will be entitled to collect from the Customer or other person benefitting from the service, under the appropriate Rate, for all power and energy not recorded on the meter as the result of such tampering, or other theft of service, and also additional security deposits as well as all expenses incurred by the Company for property damages, investigation of the illegal act, and all legal expenses and court costs incurred by the Company.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

5. The Customer will be held liable for any loss or damage occasioned or caused by the Customer's negligence, want of proper care or wrongful act or omission on the part of any Customer's agents, employees, licensees or contractors.

J. Access

1. The Customer is responsible for providing safe access to Company facilities. The Company's authorized agents shall have satisfactory unassisted twenty-four (24) hour a day, seven (7) days a week access to the Company's equipment located on Customer's premise for the purpose of service connection, service disconnection, operation, maintenance, repair and service restoration work that the Company may need to perform.

2. If additional resources are required to gain safe access to perform service establishment, disconnection, meter reading, or routine maintenance, due to an affirmative, wrongful, and/or criminal act by the Customer, the Company will be entitled to collect from the Customer all expenses incurred by the Company for additional resources including: investigation of access, all legal expenses, and court costs.

K. Customer-Specific Information

Customer-specific information shall not be released without specific prior Customer authorization unless the information is requested by law enforcement or other public agency, or is requested by the Commission or its staff, or is reasonably required for legitimate account collection activities, or is necessary to provide safe and reliable service to the Customer. Such Customer authorization may be obtained electronically, in writing, or orally, as long as the oral authorization is recorded.

SECTION 4
MINIMUM CUSTOMER INFORMATION REQUIREMENTS

A. Information for Customers

1. The Company will make available upon Customer request not later than sixty (60) days from the date of the request a concise summary of the Rate schedule applied for by the Customer. The summary will include the following:

   a. The monthly minimum Customer charge, identifying the amount of the charge and the specific amount of usage included in the minimum charge, where applicable;

   b. Rate blocks, where applicable;

   c. Any adjustment factor(s) and method of calculation; and

   d. Demand charge, where applicable.

2. Upon request of the Customer, either at the time of application or after, the Company will use its best efforts to assist the Customer in choosing an appropriate Rate. However, upon application or upon request for assistance, the Applicant or the Customer will elect the applicable Rate best suited to his requirements. The Company may assist in making this election, but will not be held responsible for notifying the Customer of the most favorable Rate and will not be required to refund the difference in charges under different Rates. The Customer is solely responsible for selecting the Rate the Customer believes is appropriate. If no Rate is selected; the Customer will be placed on the most common Rate for the class of service and the Company will not be liable to refund the difference in charges had the Customer been placed on different Rates.

3. Upon written notification of any material changes in the Customer's installation or load conditions, the Company will assist in determining if a change in Rate is desirable, but not more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

4. The supply of electric service under a residential Rate to a dwelling involving some business or professional activity will be permitted only where this activity is only occurring occasionally at the dwelling, where the electricity used in connection with this activity is small in amount, and where the electricity is used only by equipment that would normally be in use if the space were used as living quarters. Where a portion of the dwelling is used regularly for business, professional and other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or for electrical equipment not normally used in living quarters is installed in connection with the activities referenced above, then the entire premises will be classified as non-residential and the appropriate general service Rate will be applied. The Customer, may, at his option, provide separate wiring so that the residential uses can be metered and billed separately under the appropriate residential service rate schedule, and the other uses under the appropriate general service rate.

SECTION 4
MINIMUM CUSTOMER INFORMATION REQUIREMENTS
(continued)

5. In addition, the Company will make available upon Customer request, not later than sixty (60) days from date of service commencement, a concise summary of the Company's Rates or the ACC's Rules and Regulations concerning:

   a. Deposits;

   b. Termination of service;

   c. Billing and collection; and

   d. Complaint handling.

6. The Company, upon request of a Customer, will transmit a written statement of actual consumption by the Customer for each billing period during the prior twelve (12) months, unless this data is not reasonably ascertainable. But the Company will not be required to accept more than one such request from each Customer in a calendar year. The Company may charge the Customer for consumption history requests as set forth as Fee No. 8 in UNS Electric Statement of Charges.

B. Information Required Due to Changes in Rates:

1. The Company will send to affected Customers a concise summary of any change in the Rates affecting those Customers.

2. This information will be sent to the affected Customer within sixty (60) days of the effective date of the change.

SECTION 5
MASTER METERING

A. Mobile Home Parks – New Construction/Expansion

1. The Company will refuse service to all new construction or expansion of existing permanent residential mobile home parks unless the construction or expansion is individually metered by the Company. Line extensions and service connections to serve this expansion will be governed by the Company's Line Extension and/or service connection policies of these Rules and Regulations.

2. Permanent residential mobile home parks for the purpose of this rule will mean mobile home parks where the average length of stay for an occupant is a minimum of six (6) months.

3. For the purposes of this rule, expansion means the acquisition of additional real property for permanent residential spaces in excess of that existing at the effective date of this rule.

B. Residential Apartment Complexes, Condominiums and other Multiunit Residential Buildings

1. Master metering will not be allowed for new construction of apartment complexes and condominiums unless the building or buildings will be served by a centralized heating, ventilation, or air conditioning system and the contractor can provide to the Company an analysis demonstrating that the central unit will result in a favorable cost/benefit relationship.

2. At a minimum, the cost/benefit analysis should consider the following elements for a central unit as compared to individual units:

    a. Equipment and labor costs;

    b. Financing costs;

    c. Maintenance costs;

    d. Estimated kWh usage;

    e. Estimated kW demand on a coincident demand and non-coincident demand basis (for individual units);

    f. Cost of meters and installation; and

    g. Customer accounting cost (one account vs. several accounts).

3. A Customer of any residential apartment complex, condominium, or other multiunit residential building taking service through a master meter is responsible for determining his or her own usage beyond the Company's meter.

SECTION 6
SERVICE LINES AND ESTABLISHMENTS

A. Priority and Timing of Service Establishments

1. After the Applicant has complied with the Company's application requirements and has been accepted for service by the Company, and obtained all required permits and/or inspections indicating that the Customer's facilities comply with local construction, safety and governmental standards or regulations, the Company will schedule that Customer for service establishment.

2. All charges are due and payable before the Company will schedule the Customer for service establishment.

3. Service establishments will be scheduled for completion within five (5) business days of the date the Customer has been accepted for service, except in those instances when the Customer requests service establishment beyond the five (5) business day limitation.

4. When the Company has made arrangements to meet with a Customer for service establishment purposes and the Company or the Customer cannot make the appointment during the prearranged time, the Company will reschedule the service establishment to the satisfaction of both parties.

5. The Company will schedule service establishment appointments within a maximum range of four (4) hours during normal business hours, unless another timeframe is mutually acceptable to both the Company and the Customer.

6. Service establishments will be made only by the Company.

B. For the purposes of the rule, service establishments are where the Customer's facilities are ready and acceptable to the Company and the Company needs only to install or read a meter or turn the service on.Service Lines

1. Customer provided facilities

a. Each Applicant for services will be responsible for all inside wiring including the service entrance and meter socket. For three-phase service, the Customer will provide, at the Customer's expense, all facilities including conductors and conduit, beyond the Company-designated point of delivery.

b. Meters and service switches in conjunction with the meter will be installed in a location where the meters will be readily and safely accessible for reading, testing and inspection, where these activities will cause the least interference and inconvenience to the Customer. Location of metering facilities will be determined by the Company and may or may not be at the same location as the point of delivery. However, the meter locations will not be on the front exterior wall of the home, or in the carport or garage unless mutually agreed to between the Customer or homebuilder and the Company. Without cost to the Company, the Customer must provide, at a suitable and easily accessible location, sufficient and proper space for the installation of meters.

SECTION 6
SERVICE LINES AND ESTABLISHMENTS
(continued)

c. Where the meter or service line location on the Customer's premises is changed at the request of the Customer or due to alterations on the Customer's premises, the Customer must provide and have installed, at the Customer's expense, all wiring and equipment necessary for relocating the meter and service line connection. The Company will charge the Customer for moving the meter and/or service lines.

d. Customer will provide access to a main switch or breaker for disconnecting load to enable safe installation and removal of Company meters.

2. Company-Provided Facilities

a. The Company will provide, at no charge, an overhead service line up to five hundred fifty (550) feet for each Customer. In areas where the Company maintains an underground distribution system, the Company will provide, install, and connect, at no charge, underground service cable up to five hundred fifty (550) feet for each residential Customer.

b. The cost of any service line in excess of that allowed under 2.a. above will be paid for by the Customer as a contribution in aid of construction.

c. A Customer requesting an underground service line in an area served by overhead facilities will pay for the difference between estimated cost of an equivalent overhead service connection and the actual cost of the underground connection as a non-refundable contribution.

3. Overhead Service Connection – Secondary Service

a. For the initial service drop: Where the Company's distribution pole line is located on the Customer's premises, or on a street, highway, lane, alley, road, or private easement immediately contiguous thereto, the Company will, at its own expense, furnish and install a single span of service drop line (up to 550 feet in total) from its pole to the Customer's point of attachment, provided that this point of attachment is at the point of delivery and is of a type and so located that the service drop wires may be installed in a manner approved by the Company in accordance with good engineering practice, and in compliance with all applicable laws, ordinances, Rules and Regulations, including those governing clearances and points of attachment.

b. Whenever any of the clearances required by the applicable laws, ordinances, rules or regulations of public authorities or standards of the Company from the service drops to the ground or any object becomes impaired by reason of any changes made by the owner or tenant of the premises, the Customer will, at his own expense, provide a new and approved support, in a location approved by the Company, for the termination of the Company's service drop wires and will also provide all service entrance corridors and equipment necessitated by the change of location.

c. The cost of any service line footage, in excess of that allowed at no charge, will be paid for by the Customer as a contribution in aid of construction.

SECTION 6
SERVICE LINES AND ESTABLISHMENTS
(continued)

d. For each overhead service connection, the Customer will furnish at their own expense a set of service entrance conductors that will extend from the point of service delivery at the point of termination of the Company's service drop on the Customer's support to the Customer's main disconnect switch. These service entrance conductors will be of a type and be in an enclosure that meets with the approval of the Company and any inspection authorities having jurisdiction.

4. Underground Service Connections – Secondary Service

a. In areas where the Company maintains an underground distribution system, individual services will be underground.

b. The cost of any underground service line footage, in excess of that allowed at no charge, will be paid for by the Customer and will be treated as a contribution in aid of construction.

c. Whenever the Company's underground distribution system is not complete to the point designated by the Company where the service lateral is to be connected to the distribution system, the system may be extended in accordance with Section 7.

d. For an initial underground service connection of single-phase service, the Company will install a service lateral from its distribution line to the Customer's Company-approved termination facilities under the following conditions (unless otherwise agreed to by the Company and the Applicant):

(i) The Customer, at his expense, will provide the necessary trenching, conduit, conduit installation, backfill, landscape restoration and paving and will also furnish, install, own and maintain termination facilities on or within the building to be served.

e. The Company, at its expense (up to 550 feet in total), will furnish, install, own and maintain the underground single-phase cables to Customer's Company-approved termination facilities.

f. The Company will determine the minimum size and type of conduit and conductor for the single-phase service. The Customer will furnish and install the conduit system, including suitable pull ropes as specified by the Company. The ownership of this conduit or duct will be conveyed to the Company, and the Company will thereafter maintain the conduit or duct. The maximum length of any lateral conductor will be determined by the Company in accordance with accepted engineering practice in determining voltage drop, voltage flicker, and other relevant considerations.

g. For three-phase service, the Customer will provide, at the Customer's expense, all facilities, including conductors and conduit, beyond the Company-designated point of delivery.

SECTION 6
SERVICE LINES AND ESTABLISHMENTS
(continued)

C. Easements and Rights-of-Way

1. At no cost to the Company, each Customer will grant adequate easements and rights-of-way that are satisfactory to ensure proper service connection and any additional easements and rights-of-way as may be necessary for electric system reliability. Failure on the part of the Customer to grant adequate easement and right-of-way will be grounds for the Company to refuse service.

2. When the Company discovers that a Customer or the Customer's Agent is performing work, has constructed facilities or has allowed vegetation to grow adjacent to or within an easement or right-of-way and this work, construction, vegetation or facility poses a hazard or is in violation of federal, state or local laws, ordinances, statutes, Rules or Regulations, or significantly interferes with the Company's access to equipment, the Company will notify the Customer or the Customer's Agent and will take whatever actions are necessary to eliminate the hazard, obstruction or violation at the Customer's expense.

D. Number of Services to be Installed

Unless otherwise provided herein, or in a Rate or contract, the Company will not install more than one service, either overhead or underground, for any one building or group of buildings on a single premise. Separate services may be installed for separate buildings or group of buildings where necessary for the operating convenience of the Company, where provided for in the Rates, or where required by law or local ordinance.

E. Multiple Service Points

Unless otherwise expressly provided herein, or in a Rate or contract, any person, firm, corporation, agency or other organization or governmental body receiving service from the Company at more than one location or for more than one separately operated business will be considered as a separate Customer at each location and for each business. If several buildings are occupied and used by a Customer in the operation of a single business, then the Company, upon proper application, will furnish service for the entire group of buildings through one service connection at one point of delivery, provided all of these buildings are at one location on the same lot or tract, or on adjoining lots or tracts that form a contiguous site (not separated by any public streets) wholly owned, or controlled, and occupied by the Customer in the operation of this single business. Dwelling units will be served, metered and billed separately, except at the option of the Company.

F. Temporary Service

For service that is temporary in nature or for operations of a speculative character or questionable permanency the Customer will be charged the Company's estimated cost of installing and removing the service.

SECTION 6
SERVICE LINES AND ESTABLISHMENTS
(continued)

G. Customer-Owned Cable

When a residential Customer's privately owned underground service cable has failed, the Customer has two (2) options:

1. The Customer can have their cable repaired by a private electrical contractor which must comply with local governmental codes and ordinances; or

2. The Customer can bring their service entrance up to current Company standards. The Customer will be required to provide a service trench, conduit, conduit installation, backfill, landscape restoration and paving. The Company will furnish, install, own and maintain its underground single-phase cables to the Customer's Company-approved Point of Delivery.

SECTION 7
LINE EXTENSIONS

Introduction

The Company will construct, own, operate and maintain lines along public streets, roads and highways which the Company has the legal right to occupy, and on public lands and private property across which rights-of-way and easements satisfactory to the Company may be obtained without cost to or condemnation by the Company.

A request for electric service often requires the construction of new distribution lines of varying distances. The distances and cost vary widely depending upon Customer's location and load size. With such a wide variation in extension requirements, it is necessary to establish conditions under which the Company will extend its electric facilities.

All extensions are subject to the availability of adequate capacity, voltage and Company facilities at the beginning point of an extension, as determined by the Company.

A standard policy has been adopted to provide service to Customers whose requirements are deemed by the Company to be economical and ordinary in nature.

All extensions are made on the basis of economic feasibility. Footage and revenue basis are offered below for use in circumstances where feasibility is generally accepted because of the number of extensions made within these footage and dollar units.

In unusual circumstances, when the application of the provisions of this policy appear impractical, or in case Customer's requirements exceed 100 kW, the Company will make a special study of the conditions to determine the basis on which service may be rendered.

A. General Requirements

1. Upon request by an Applicant for a line extension, the Company will prepare without charge, a preliminary electric design and a rough estimate of the cost of installation, if any, to be paid by said Applicant.

2. Any Applicant for a line extension requesting the Company to prepare detailed plans, specifications, or cost estimates will be required to make a non-refundable deposit with the Company in an amount equal to the estimated cost of preparation. The Company will make available within ninety (90) days after receipt of the deposit referred to above, those plans, specifications, and cost estimates for the proposed line extension. Where the Applicant authorizes the Company to proceed with construction of the extension, the deposit will be credited to the cost of construction. If the extension is to include over-sizing of facilities to be done at the Customer's expense, appropriate details will be set forth in the plans, specifications and cost estimates. Developers providing the Company with approved plats will be provided with plans, specifications, or cost estimates within ninety (90) days after receipt of the deposit referred to above.

   The Company will provide a copy of the Line Extension policy prior to the Applicant's acceptance of the utility's extension agreement.

SECTION 7
LINE EXTENSIONS
(continued)

3. All line extension agreements requiring payment of an advance by the Applicant will be in writing and signed by each party.

4. The provisions of this rule apply only to those Applicants who, in the Company's judgment, will be permanent Customers of the Company. Applications for temporary service will be governed by the Company's Rules concerning temporary service applications. The Company reserves the right to delay the extension of facilities until the satisfactory completion of required site improvements, as determined by the Company, and an approved service entrance to accept electric service has been installed.

B. Minimum Written Agreement Requirements

1. Each line extension agreement must, at a minimum, include the following information:

   a. Name and address of Applicant(s);

   b. Proposed service address(es) or location(s);

   c. Description of requested service;

   d. Description and sketch of the requested line extension;

   e. A cost estimate to include material costs, labor costs, overhead costs, and any other costs as necessary.

   f. Payment terms;

   g. A concise explanation of any refunding provisions, if applicable;

   h. The Company's estimated start date and completion date for construction of the line extension; and

   i. A summary of the results of the economic feasibility analysis performed by the Company to determine the amount of the advance required from the Applicant for the proposed line extension.

2. Each Applicant will be provided with a copy of the written line extension agreement.

SECTION 7
LINE EXTENSIONS
(continued)

C. Line Extension Requirements

1. Overhead Extensions to Individual Residential Applicants

a. Line Extension Allowance

Upon the Applicant's satisfactory completion of required site improvements, the Company will make single-phase extensions from its existing facilities of proper voltage and adequate capacity at the Company's expense up to five hundred fifty (550) feet. The distance of five hundred fifty (550) feet is to be measured by the shortest feasible route along public streets, roads, highways, or suitable easements from the existing facilities to the Applicant's nearest point of delivery and inclusive of the service drop and is for initial site improvements, as determined by the Company, only.

b. Extensions in Excess of Line Extension Allowance Distance

The Company will make extensions in excess of five hundred fifty (550) feet per Customer upon receipt of a non-interest bearing, refundable cash deposit with the Company to cover the estimated costs of construction for the pro-rata share of the single-phase extension length over five hundred fifty (550) feet, for voltages up to 21kV.

The Company will install, own and maintain, on an individual project basis, the distribution facilities necessary to provide permanent service.

c. Method of Refund

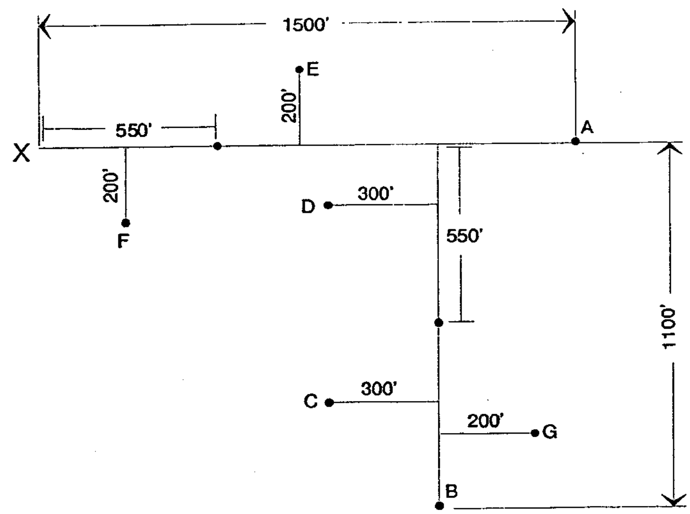
i. Deposit refunds will be made to a depositor when separately metered Customers are served directly from the line extension originally constructed to serve said depositor, providing the new line extension is less than five hundred fifty (550) feet in distance, and the Customer to be served occupies a permanent structure designed for continued occupancy for either residential or business purposes, meeting established municipal, county or state codes as applicable.

The amount of the deposit refund will be equal to the estimated 'Cost per Foot' for the line extension project rate multiplied by five hundred fifty (550) feet less the actual footage of the new line extension required to serve the new Customer.

In no event will the total of the refund payments made by the Company to a depositor be in excess of the deposit amount advanced.

SECTION 7
LINE EXTENSIONS
(continued)

A pictorial explanation of the method of refund for a single-phase line extension is as follows (assume the 'Cost per Foot' rate for this Line Extension is $15.00 per foot):



Applicant "A" – Customer makes refundable advance of $14,250 for footage over 550' at $15.00/foot.

Applicant "B" – Customer makes refundable advance of $8,250 for footage over 550' at $15.00/foot. No refund to A for B's connection because B is over 550'.

Applicant "C" – Customer gets line at no cost. Refund goes to B at $15.00 x 250', or $3,750 because C ties directly into B's line and is less than 550'.

Applicant "D" – Customer gets line at no cost. Refund goes to B at $15.00 x 250', or $3,750, because it ties directly into B's line and is less than 550'.

Applicant "E" – Customer gets line at no cost. Refund goes to A at $15.00 x 350', or $5,250 because E ties directly into A's line and is less than 550'.

Applicant "F" – Customer gets line at no cost. Refund goes to A at $15.00 x 350', or $5,250 because F ties directly into A's line and is less than 550'.

Applicant "G" – Customer gets line at no cost. Refund goes to B at $15.00 x 350', or $5,250; however, B receives $750 since this is the remaining balance of the initial deposit net of refunds. Total refunds cannot exceed the amount of the initial advance.

SECTION 7
LINE EXTENSIONS
(continued)

Note: The dollars in the example above are illustrative. This method requires that: a) The deposit advance made for an initial line extension cannot be refunded to the depositor unless a new line extension required to serve a new separately metered Customer is directly connected to the initial line extension; and b) the new line extension is less than 550 feet in length.

ii. Payment of eligible refunds will be made within ninety (90) days following receipt of notification to the Company that a qualifying permanent Customer has commenced receiving service from an extension.

iii. A Customer may request an annual survey to determine if additional Customers have been connected to and are using service from the extension.

iv. After a period of five (5) years from the date the Company is initially ready to render service from an extension, the Company will review the deposit and make appropriate refunds then due, if any. Any unrefunded amount remaining thereafter will become the property of the Company and will no longer be eligible for refund and will become a contribution in aid of construction.

2. Underground Facilities to Individual Residential Applicants

a. Underground line extensions will generally be made only where mutually agreed upon by the Company and the Applicant, or in areas where the Company does maintain underground distribution facilities for its operating convenience.

b. Underground extensions will be owned, operated and maintained by the Company, provided the Applicant pays in advance a non-refundable sum equal to the estimated difference between the cost, exclusive of meters and services, of the underground extension and an estimated equivalent overhead extension cost for voltages up to 21kV.

c. In addition to the non-refundable sum, the Applicant will (unless otherwise agreed to by the Company and the Applicant) make such refundable deposit (for voltages up to 21kV) in accordance with Subsection 7.C. as otherwise would have been required under these Rules and Regulations if the extension had been made by overhead construction.

d. Refunds of cash deposits will be made in the same manner as provided for overhead extensions to individual Applicants for service, in accordance with the applicable provisions of Subsection 7.C.

e. Underground services will be installed, owned, operated and maintained as provided in Section 6 of these Rules and Regulations.

SECTION 7
LINE EXTENSIONS
(continued)

3. Extensions to Non-Residential Customers

   a. Line Extensions less than 21kV

      i. For line extensions with voltages less than or equal to 21kV, the Company will install, own and maintain, on an individual project basis, the distribution facilities necessary to provide permanent service to a non-residential Customer. Prior to the installation of facilities, the Customer will be required to make a refundable non-interest-bearing cash advance to the Company for the estimated project cost less an allowance equal to 50% of the estimated two year Revenue. If the total of such charge is less than one hundred dollars ($100.00), the charge will be waived by the Company.

      ii. Upon completion of construction of the Company's facilities the total actual cost of the project will be compared to the total estimated cost advanced by the Applicant, and any difference will be either billed or refunded within ninety (90) days to the Customer.

      iii. After the initial twenty-four (24) month billing period the Company will compare the actual Revenue to the allowance, and any difference will be either billed or refunded within ninety (90) days to the Customer.

      iv. In no event shall the total of the refund payments made by the Company to the depositor be in excess of the deposit amount advanced.

      v. No refunds will be made after a period of two (2) years subsequent to the completion of construction of the Company's facilities. Any un-refunded amount remaining at the end of the two (2) year period will become the property of the Company and a nonrefundable contribution in aid of construction.

      vi. 550 foot line extension allowance does not apply.

   b. Line Extensions greater than 21kV to 69kV

      i. For line extensions with voltages greater than 21kV and less than or equal to 69kV, the Company will install, own and maintain, on an individual project basis, the distribution facilities necessary to provide permanent service to a non-residential Customer. Prior to the installation of facilities, the Customer will be required to make a refundable non-interest-bearing cash advance to the Company for the estimated project cost less an allowance equal to 50% of the estimated one year Revenue. If the total of such charge is less than one hundred dollars ($100.00), the charge will be waived by the Company.

      ii. Upon completion of construction of the Company's facilities the total actual cost of the project will be compared to the total estimated cost advanced by the Applicant, and any difference will be either billed or refunded within ninety (90) days to the Customer.

      iii. After the initial twelve (12) month billing period the Company will compare the actual Revenue to the allowance, and any difference will be either billed or refunded within ninety (90) days to the Customer.

SECTION 7
LINE EXTENSIONS
(continued)

iv. In no event shall the total of the refund payments made by the Company to the depositor be in excess of the deposit amount advanced.

v. No refunds will be made after a period of two (2) years subsequent to the completion of construction of the Company's facilities. Any un-refunded amount remaining at the end of the two (2) year period will become the property of the Company and a nonrefundable contribution in aid of construction.

vi. 550 foot line extension allowance does not apply.

4. Residential Subdivision Developers

a. General

Required distribution facilities up to and within a new duly recorded residential subdivision, including subdivision plats which are activated subsequent to their recordation, for permanent service to single and/or multi-family residences and/or unmetered area lighting, will be constructed, owned, operated and maintained by the Company in advance of applications for service by permanent Customers only after the Company and the Applicant have entered into a written contract ("Subdivision Agreement"), which (unless otherwise agreed to by the Company and the Applicant) provides that:

i. The total estimated installed cost of such overhead distribution facilities, exclusive of meters, services and exclusive of other costs as may be deemed as reasonable by the Company, will be advanced to the Company as a refundable non-interest bearing cash deposit to cover the Company's cost of construction.

ii. Refundable advances will become non-refundable at such time and in such manner as provided in Subsection 7.C.4.b.

iii. Upon completion of construction of the Company's facilities the total actual cost of the project will be compared to the total estimated cost advanced by the Applicant, and any difference will be either billed or refunded within ninety (90) days to the Customer.

iv. Where applicable, if distribution facilities must be constructed in excess of an average of five hundred fifty (550) feet per new permanent Customer within a duly recorded residential subdivision, a nonrefundable cash amount equal to that portion of the total estimated installed cost represented by those required line facilities in excess of five hundred fifty (550) feet per Customer average will be paid to the Company.

SECTION 7
LINE EXTENSIONS
(continued)

v. Underground Installations – Extensions of single-phase underground distribution lines necessary to furnish permanent electric service to new residential buildings or mobile homes within a subdivision, in which facilities for electric service have not been constructed, for which applications are made by a developer will be installed underground in accordance with the provisions set forth in this regulation except where it is not feasible from an engineering, operational, or economic standpoint. Extensions of single-phase underground distribution lines necessary to furnish permanent electric service within a new single family and/or multi-family residential subdivision will be made by the Company in advance of receipt of applications for service by permanent Customers in accordance with the following provisions (unless otherwise agreed to by the Company and the Applicant):

1) The subdivider or other Applicant will provide the trenching, bedding, conduit, backfill (including any imported backfill required), compaction, repaving and any earthwork for pull boxes and equipment and transformer pad sites required in accordance with the Company's specifications and subject to the Company's inspection and approval.

2) Right-of-way and easements satisfactory to the Company will be furnished by the Developer at no cost to the Company and in reasonable time to meet service requirements. No underground electric facilities will be installed by the Company until the final grades have been established and furnished to the Company. In addition the easements, alleys and/or streets must be graded to within six (6) inches of final grade by the Developer before the Company will commence construction. Such clearance and grading must be maintained by the Developer. If, subsequent to construction, the clearance or grade is changed in such a way as to require relocation of underground facilities or results in damage to such facilities, the cost of such relocation and/or resulting repairs will be borne by the developer.

3) If armored cable or special cable covering is required, the Customer or developer will make a non-refundable contribution equal to the additional cost of such cable or covering.

4) Underground service lines will be installed, owned, operated and maintained as provided in Section 6 of these Rules and Regulations.

5) Any underground electric distribution system requiring more than single-phase service is not governed by this Subsection, but rather will be constructed pursuant to Subsection 7.C.7.

vi. Underground extensions up to the duly recorded Subdivision will be owned, operated and maintained by the Company, provided the Applicant pays a non-refundable sum equal to the estimated difference between the cost of the underground extension and an equivalent estimated cost of an overhead extension.

SECTION 7
LINE EXTENSIONS
(continued)

b. Method of Refund

i. The Developer is eligible for a refund during the term of the Subdivision Agreement of up to 100% of the amount advanced provided the average length of the line extension per lot or per service location does not exceed five hundred fifty (550) feet. If distribution facilities must be constructed in excess of an average of five hundred fifty (550) feet per new permanent lot or service location within a duly recorded residential subdivision, that portion of the advanced total installed cost represented by those required line facilities in excess of five hundred fifty (550) feet per customer will be held by the Company as a non-refundable contribution.

ii. On or after one (1) year subsequent to the installation of the Company's facilities, and thereafter each year of the term of the Subdivision Agreement the Company will review the status of the subdivision to determine the percentage ratio that the number of lots or service locations occupied by permanent Customers bears to the number of lots identified in each Subdivision Agreement specified as the basis for refund. The ratio determined at the time of each review multiplied by the total refundable advance associated with the line extension agreement will represent that portion of the advance qualified for refund. If the foregoing calculation indicates a refund is due, an appropriate refund of cash deposit will be made. Payment will be made within ninety (90) days following each review.

iii. The total amount refunded over the term of the Subdivision Agreement cannot exceed the total amount advanced net of any non-refundable contribution and or cost of ownership.

iv. The Company will make a final review on the status after a period of five (5) years. No refunds will be made after a period of five (5) years subsequent to the completion of construction of the Company's facilities. Any unrefunded amount remaining at the ends of the five (5) year period will become the property of the Company and a nonrefundable contribution in aid of construction.

5. Non-Residential Developers

a. General

Required distribution facilities up to and within a new duly recorded non-residential development, including commercial plats which are activated subsequent to their recordation, for permanent service, will be constructed, owned, operated and maintained by the Company in advance of applications for service by permanent commercial customers only after the Company and the Applicant have entered into a written contract which (unless otherwise agreed to by the Company and the Applicant) provides that:

i. For line extensions with voltages less than or equal to 21kV, the Company will install, own and maintain, on an individual project basis, the distribution facilities necessary to provide permanent service to a non-residential Customer. Prior to the installation of facilities, the Customer will be required to make a refundable non-interest-bearing cash advance to the Company for the estimated project cost less an allowance equal to 50% of the estimated two year Revenue. If the total of such charge is less than one hundred dollars ($100.00), the charge will be waived by the Company.

SECTION 7
LINE EXTENSIONS
(continued)

ii. Upon completion of construction of the Company's facilities the total actual cost of the project will be compared to the total estimated cost advanced by the Applicant, and any difference will be either billed or refunded within ninety (90) days to the Customer.

iii. Five-hundred fifty (550) foot line extension allowance does not apply.

iv. For line extensions with voltages greater than 21kV Subsection 7.C.3.b will apply.

b. Method of Refund

i. After the initial twenty-four (24) month billing period the Company will compare the actual Revenue to the allowance, and any difference will be either billed or refunded within ninety (90) days to the Customer.

ii. In no event shall the total of the refund payments made by the Company to the depositor be in excess of the deposit amount advanced.

iii. No refunds will be made after a period of two (2) years subsequent to the completion of construction of the Company's facilities. Any unrefunded amount remaining at the end of the two (2) year period will become the property of the Company and a nonrefundable contribution in aid of construction.

c. Underground Installations – Extensions of single-phase or three-phase underground distribution lines necessary to furnish permanent electric service to new commercial properties a commercial subdivision, in which facilities for electric service have not been constructed, for which applications are made by a developer will be installed underground in accordance with the provisions set forth in this regulation except where it is not feasible from an engineering, operational, or economic standpoint. Extensions of single-phase or three-phase underground distribution lines necessary to furnish permanent electric service will be made by the Company in advance of receipt of applications for service by permanent commercial customers in accordance with the following provisions (unless otherwise agreed to by the Company and the Applicant):

i. The subdivider or other Applicant will provide the trenching, bedding, backfill (including any imported backfill required), compaction, repaving and any earthwork for pull boxes and equipment and transformer pad sites required in accordance with the Company's specifications and subject to the Company's inspection and approval.

ii. Underground service will be installed, owned, operated and maintained as provided in Section 6 of these Rules and Regulations.

iii. Underground extensions up to the duly recorded Subdivision will be owned, operated and maintained by the Company, provided the Applicant pays a non-refundable sum equal to the estimated difference between the cost of the underground extension and an equivalent estimated cost of an overhead extension.

SECTION 7
LINE EXTENSIONS
(continued)

6. Replacement of Overhead with Underground Distribution Facilities

Where a Customer has requested that existing overhead distribution facilities be replaced with underground distribution facilities, the total cost of such replacement will be paid by the Customer.

7. Conversion from Single-Phase to Three-Phase Service

Where it is necessary to convert all or any portion of an existing overhead or underground distribution system from single-phase to three-phase service to a Customer, the total cost of such conversion will be paid by the Customer.

8. Long Term Rental Mobile Home Park, Townhouses, Condominiums and Apartment Complexes

Line extensions to long term rental mobile home parks, townhouses, condominiums and apartment complexes will be made by the Company under terms and conditions provided in Subsection 7.C.1. The Company will, when requested by the Customer, install, own and maintain internal distribution facilities and individual metering for said development in accordance with the provisions pertaining to duly recorded real estate subdivisions as stated in Subsection 7.C.2 hereof.

9. Special Conditions

a. Contracts

Each sub divider or other Applicant for service requesting an extension over the allowable footage allowance, or in advance of applications for service to permanent Customers, or in advance of completion of required site improvements will (unless otherwise agreed to by the Company and the Applicant) be required to execute contracts covering the terms under which the Company will install lines at its own expense, or contracts covering line extensions for which advance deposits will (unless otherwise agreed to by the Company and the Applicant) be made in accordance with the provisions of these Rules and Regulations or of the applicable rate schedules.

b. Primary Service and Metering

The Company will provide primary service to a point of delivery, such point of delivery to be determined by the Company. The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The system will be treated as primary service for the purposes of billing. The Company reserves the right to approve or require modification to the Customer's distribution system prior to installation, and the Company will determine the voltage available for primary service. Instrument transformers, metering riser poles and associated equipment to be installed and maintained by the Company will be at the Customer's expense.

SECTION 7
LINE EXTENSIONS
(continued)

c. Advances under Previous Rules and Contracts

Amounts advanced under the conditions established by a rule previously in effect will be refunded in accordance with the requirements of such contract under which the advance was made.

d. Extensions for Temporary Service

Extensions for temporary service or for operations of a speculative character (mining, milling, irrigation and similar speculative businesses) or questionable permanency will be charged the applicable estimated charges for the installation and removal of temporary facilities. Temporary facilities will remain in service for a maximum of two (2) years.

e. Exceptional Cases

Where unusual terrain, location, soil conditions, or other unusual circumstances make the application of these line extension rules impractical or unjust to either party or in the case of extension of lines of other than standard distribution voltage, service under such circumstances will be negotiated under special agreements specifying terms and conditions covering such extensions.

f. Special or Excess Facilities

Under this rule, the Company will install only those facilities which it deems are necessary to render service in accordance with the rate schedules. Where the Customer requests facilities which are in addition to, or in substitution for, the standard facilities which the Company normally would install, the extra cost thereof will be paid by the Customer.

g. Unusual Loads

Line extensions to unusually small loads not serving a permanent structure designed for continued occupancy for either residential or business purposes (e.g. individual lights, wells, signs, etc.) will not be granted the five hundred fifty (550) foot allowance, but will instead be required to advance any costs of service.

10. Other Conditions

a. Rights-of-Way – All necessary easements or rights-of-way required by the Company for any portion of the extension which is either on premises owned, leased or otherwise controlled by the Customer, Developer, or others will be furnished in the Company's name by the Customer without cost to or condemnation by the Company and in reasonable time to meet proposed service requirements. All easements or rights-of-way obtained on behalf of the Company will contain only those terms and conditions that are acceptable to the Company.

SECTION 7
LINE EXTENSIONS
(continued)

b. Change of Grade – If subsequent to construction of electric distribution and/or transmission lines and services, the final grade established by the Customer or Developer is changed in such a way as to require relocation of the Company facilities or results in damage to those same facilities, the cost of relocation and/or resulting repairs will be borne by the Customer or Developer.

c. Relocation – When the Company is requested to relocate its facilities for the benefit and/or convenience of a Customer, the Customer will pay the Company for the total cost of the work to be performed prior to the start of construction.

d. Connecting or Disconnecting Customer's Service – Only duly authorized employees of the Company are allowed to connect the Customer's service to, or disconnect the same from, the Company's electric lines.

e. Maintenance of Customer's Equipment – The Customer will, at the Customer's own risk and expense, furnish, install and keep in good and safe condition all electrical wires, lines, machinery and apparatus which may be required for receiving electric energy from the Company, and for applying and utilizing that energy, including all necessary protective appliances and suitable building therefore, and the Company will not be responsible for any loss or damage occasioned or caused by the negligence, want of proper care, or wrongful act of the Customer or any of the Customer's agents, employees or licensees on the part of the Customer in installing, maintaining, using, operating or interfering with any such wires, lines, machinery or apparatus.

f. Removal of Company Property – As provided for in these Rules and Regulations, the Company will have the right to remove any and all of its property installed on the Customer's premises at the termination of service.

g. Change of Customer's Requirements – In the event that the Customer must make any material change either in the amount or character of the appliances or apparatus installed upon the Customer's premises to be supplied with electric energy by the Company, the Customer must immediately give the Company written notice to this effect.

h. Refunds – In no case will the total of any refund payments made by the Company exceed the amount of any construction advance

i. Collections – Nothing in these Rules and Regulations will be construed as limiting or in any way affecting the right of the Company to collect from the Customer any other additional sum of money which may become due and payable.

SECTION 7
LINE EXTENSIONS
(continued)

D. Construction / Facilities Related Income Taxes

1. Collection of Income Tax Gross Up

a. Any federal, state or local income taxes resulting from the receipt of a Contribution or Advance in Aid of Construction in compliance with this rule is the responsibility of the Company and will be recorded as a deferred tax asset and reflected in the Company's rate base for ratemaking purposes.

b. However, if the estimated contribution or advance for any service line or distribution main extension (as determined for each individual extension agreement) exceeds $500,000, the Company shall require the Applicant to include in the contribution or advance an amount (the "gross up amount") equal to the estimated federal, state or local income tax liability of the Company resulting from the contribution or advance computed as follows:

$$\text{Gross Up Amount} = \frac{\text{Advance or Contribution}}{(1 - \text{Statutory combined income tax rate})} - \text{Advance or Contribution}$$

c. After the Company's tax returns for the year of receipt of the advance or contribution are completed, if the statutory combined income tax rate is less than the rate used to calculate the gross-up, the Company shall refund to the Applicant an amount equal to such excess.

d. When a gross-up amount is to be collected in connection with an extension agreement, the contract will state the tax rate used to compute the gross up amount, and will also disclose the gross-up amount separately from the estimated cost of facilities.

2. Refund of Tax Gross Up

a. In the case of construction advance refunds made pursuant to Subsection 7.C.3 a pro rata portion of the gross up will be refunded when the amount of the underlying advance is refunded. Any remaining gross-up will be refunded on November 1 of each year as tax depreciation deductions are taken on the Company's tax returns. At the end of five (5) years from installation, the remaining gross up will be refunded at an amount that reflects the net present value of the Company's remaining tax depreciation deductions on the underlying advance discounted at the Company's authorized rate of return.

b. In the case of all other advances or deferred construction deposit agreements, the gross up will be refunded, or the amount of required deferred construction deposit will be reduced, as follows:

i. If the full amount of the advance is refunded prior to September 30th of the year following the year in which the advance is received, the entire amount of the gross-up will be refunded.

SECTION 7
LINE EXTENSIONS
(continued)

ii. For any amount of the advance not refunded as of September 30th of the year following the year in which the advance is received, on November 1st of each year a portion of the gross-up will be refunded based on the amount of the tax depreciation deductions taken by the Company on its federal and state income tax returns.

iii. When any advance is refunded after depreciation refunds pursuant to clause ii have begun, a pro rata portion of the gross up will be refunded reduced by the amount of depreciation refunds previously made for that portion of the gross up.

iv. For any advance that is not refunded at the end of the contract period, the remaining gross up will be refunded at an amount that reflects the net present value of the Company's remaining tax depreciation deductions on the underlying advance discounted at the Company's authorized rate of return.

3. Non-refundable Income Tax Gross Up for Contribution in Aid of Construction

a. At the option of the Customer, a non-refundable gross-up may be calculated as follows:

$$\text{Non-refundable Gross Up Amount} = \frac{(\text{Contribution Amount} - \text{Net Present Value of Tax Depreciation})}{(1 - \text{Current Tax Rate})} - \text{Contribution Amount}$$

4. Alternate Income Tax Gross Up for Advances in Aid of Construction

a. At the option of the Customer, a gross-up may be calculated as in Section 7.D.3.a when an advance is received. When the Customer has received its final advance refund the alternate gross-up will be recomputed as follows:

$$\text{Alternate Gross Up Amount} = \frac{(\text{Advance Amount} - \text{Net Present Value of (Advance Refunds + Tax Depreciation on Advances Not Refunded)})}{(1 - \text{Current Tax Rate})} - \text{Advance Amount}$$

SECTION 8
PROVISION OF SERVICE

A. Company Responsibility

1. The Company will be responsible for the safe transmission and distribution of electricity until it passes the point of delivery to the Customer.

2. The Company will be responsible for maintaining in safe operating condition all meters, equipment and fixtures installed on the Customer's premises by the Company for the purpose of delivering electric service to the Customer. However, the Company will not be responsible for the condition of meters, equipment, and fixtures damaged or altered by the Customer.

3. The Company may, at its option, refuse service until the Customer has obtained all required permits and/or inspections indicating that the Customer's facilities comply with local construction and safety standards, including any applicable Company specifications.

4. The Company will determine, in its sole discretion, the type of service (including voltage and Point of Delivery) to be furnished for utilization by the Customer. This includes determinations involving: 1) requirements to take Primary Service and Metering; and 2) service voltage (including for any new on-site generation installations or generation retrofits at the Customer's premises).

B. Customer Responsibility

1. Each Customer will be responsible for maintaining in safe operating condition all Customer facilities on the Customer's side of the point of delivery.

2. Each Customer will be responsible for safeguarding all Company property installed in or on the Customer's premises for the purpose of supplying electric service to that Customer.

3. Each Customer will exercise all reasonable care to prevent loss or damage to Company property, excluding ordinary wear and tear. The Customer will be responsible for loss of or damage to Company property on the Customer's premises arising from neglect, carelessness, misuse, diversion, or tampering and will reimburse the Company for the cost of necessary repairs or replacements.

4. Each Customer will be responsible for payment for any equipment damage and/or estimated unmetered usage and all reasonable costs resulting from unauthorized breaking of seals, interfering, tampering or bypassing the Company meter.

5. Each Customer will be responsible for notifying the Company of any equipment failure identified in the Company's equipment.

SECTION 8
PROVISION OF SERVICE
(continued)

6. Each Customer will be responsible for informing the Company of, and meeting the Company's requirements regarding on-site or distributed generation (including distributed renewable resources and combined heat and power facilities) that the Customer or the Customer's agent intends to interconnect to the Company's transmission or distribution system. This includes compliance with all requirements contained within the Company's most current Interconnection Requirements for Distributed Generation, and the terms and conditions of the Company's Agreement for the Interconnection of Customer's Facility. Customer must also agree to enter into the Interconnection Agreement with the Company. Further, any interconnection must be in accordance with any applicable Commission regulation and order governing interconnection, as well as applicable laws.

7. The Customer, at his expense, may install, maintain and operate check-measuring equipment as desired and of a type approved by the Company, provided that this equipment will be installed so as not to interfere with operation of the Company's equipment. This is also provided that no electric energy will be remetered or submetered for resale to another or to others, except where such remetering will be done in accordance with the applicable orders of the Commission.

C. Continuity of Service

The Company will make reasonable efforts to supply a satisfactory and continuous level of service. However, the Company will not be responsible for any damage or claim of damage attributable to any interruption or discontinuation of service resulting from:

1. Any cause against which the Company could not have reasonably foreseen, or made provision for (*i.e* force majeure, see Subsection 8.E.);

2. Intentional service interruptions to make repairs or perform routine maintenance; or

3. Curtailment, including brownouts or blackouts.

D. Service Interruptions

1. The Company will make reasonable efforts to reestablish service within the shortest possible time when service interruptions occur.

2. In the event of a national emergency or local disaster resulting in disruption of normal service, the Company may, in the public interest, interrupt service to other Customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

SECTION 8
PROVISION OF SERVICE
(continued)

3. When the Company plans to interrupt service for more than four (4) hours to perform necessary repairs or maintenance, the Company will attempt to inform affected Customers at least twenty-four (24) hours in advance of the scheduled date and these repairs will be completed in the shortest possible time to minimize the inconvenience to the Customers of the Company.

4. The Commission will be notified of interruption in service affecting the entire system or any significant portion thereof. The interruption of service and cause will be reported by telephone to the Commission within four (4) hours after the responsible Company representative becomes aware of said interruption. A written report to the Commission will follow.

E. Interruption of Service and Force Majeure

1. The Company will make reasonable provision to supply a satisfactory and continuous electric service, but does not guarantee a constant or uninterrupted supply of electricity. The Company will not be liable for any damage or claim of damage attributable to any temporary, partial or complete interruption or discontinuance of electric service attributable to a force majeure condition as set forth in Subsections 8.E.4. and 8.E.5. or to any other cause which the Company could not have reasonably foreseen and made provision against, or which, in the Company's judgment, is necessary to permit repairs or changes to be made in the Company's electric generating, transmission, or distribution equipment, or to eliminate the possibility of damage to the Company's property or to the person or property of others.

2. Whenever the Company deems a condition exists that warrants interruption or limitation in the service being rendered, this limitation or interruption will not constitute a breach of contract and will not render the Company liable for damages suffered thereby or excuse the Customer from further fulfillment of the contract.

3. The use of electric energy upon the Customer's premises is at the risk of the Customer. The Company's liability will cease at the point where its facilities are connected to the Customer's wiring.

4. Neither the Company nor the Customer will be liable to the other for any act, omission, or circumstances (including, but not limited to, the Company's inability to provide electric service) occasioned by or in consequence of the following:

   a. flood, rain, wind, storm, lightning, earthquake, fire, landslide, washout or other acts of the elements;

   b. accident or explosion;

   c. war, rebellion, civil disturbance, mobs, riot, blockade or other act of the public enemy;

   d. acts of God;

   e. interference of civil and/or military authorities;

SECTION 8
PROVISION OF SERVICE
(continued)

f. strikes, lockouts, or other labor difficulties;

g. vandalism, sabotage, or malicious mischief;

h. usurpation of power, or the laws, rules, regulations, or orders made or adopted by any regulatory or other governmental agency or body (federal, state or local) having jurisdiction of any of the business or affairs of the Company or the Customer, direct or indirect;

i. breakage or accidents to equipment or facilities;

j. lack, limitation or loss of electrical or fuel supply; or

k. any other casualty or cause beyond the reasonable control of the Company or the Customer, whether or not specifically provided herein and without limitation to the types enumerated, and which by exercise of due diligence the Company or the Customer is unable to overcome.

5. A failure to settle or prevent any strike or other controversy with employees or with anyone purporting or seeking to represent employees will not be considered to be a matter within the control of the Company.

6. Nothing contained in this Section will excuse the Customer from the obligation of paying for electricity delivered or services rendered.

F. General Liability

1. Company will not be responsible for any third-party claims against Company that arise from Customer's use of Company's electric services, unless such claims are caused by the Company's willful misconduct or gross negligence.

2. Customer will indemnify, defend and hold harmless the Company (including the costs of reasonable attorney's fees) against all claims (including, without limitation, claims for damages to any business or property, or injury to, or death of, any person) arising out of any wrongful or negligent acts or omissions of the Customer, or the Customer's agents, in connection with the Company's service or facilities.

3. The liability of the Company for damages of any nature arising from errors, mistakes, omissions, interruptions, or delays of the Company, its agents, servants, or employees, in the course of establishing, furnishing, rearranging, moving, terminating, or changing the service or facilities or equipment shall not exceed an amount equal to the charges applicable under the Company's Rates (calculated on a proportionate basis where appropriate) to the period during which the error, mistake, omission, interruption or delay occurs, except if such damages are caused by the Company's willful misconduct or gross negligence.

SECTION 8
PROVISION OF SERVICE
(continued)

4. In no event will the Company be liable for any incidental, indirect, special, or consequential damages (including lost revenue or profits) of any kind whatsoever regardless of the cause or foreseeability thereof.

5. The Company will not be responsible in an occasion for any loss or damage caused by the negligence or wrongful act of the Customer or any of his agents, employees or licensees in installing, maintaining, using, operating or interfering with any electric facilities.

G. Construction Standards and Safety

The Company will construct all facilities in accordance with the provisions of the ANSI C2 Standards (National Electric Safety Code, 2007 edition, and other amended editions as are adopted by the ACC), the 2007 ANSI B31.1 Standards, the ASME Boiler and Pressure Vessel Code, and other applicable American National Standards Institute Codes and Standards, except for those changes the ACC makes or permits from time to time. In the case of conflict between codes and standards, the more rigid code or standard will apply.

SECTION 9
CHARACTER OF SERVICE – VOLTAGE, FREQUENCY AND PHASE

A. For Residential, Lighting and Miscellaneous Service – Energy supplied will be sixty (60) Hertz, single phase, alternating current, three-wire service, 120/240 volts for new service applications. The Company will provide 120 volts, two-wire for those Customers currently receiving that service.

B. Commercial and Industrial Service – Electric energy furnished under these Rules and Regulations will be sixty (60) Hertz alternating current energy, single or three (3) phase at the standard nominal voltages specified by the Company.

C. All electric energy supplied will be in accordance with ANSI voltage ratings for electric power systems and equipment.

D. All voltages referred to above are nominal voltages and may vary somewhat due to local conditions. The Company does not guarantee the constancy of its voltage or frequency, nor does it guarantee against its loss of one or more phases in a three-phase service. The Company will not be responsible for any damage to the Customer's equipment caused by any or all of these occurrences brought about by circumstances beyond its control.

E. Motor Protection

The following protective apparatus, to be provided by the Customer, is required on all motor installations:

1. No Voltage Protection: Motors that cannot be safely subjected to full voltage at starting must be provided with a device to insure that upon failure of voltage, the motors will be disconnected from the line. Said device should be provided with a suitable time delay relay;

2. Overload Protection: All motors whose voltage does not exceed 750 volts are to be provided with approved fuses of proper rating. Where the voltage exceeds 750 volts, protective devices are to be provided. In these cases it will be found desirable to install standard switching equipment. The installation of overload relays and no-voltage releases is recommended on all motors, not only as additional protection, but as a means of reducing the cost of refusing; and

3. Phase Reversal: Reverse phase relays and circuit breakers or equivalent devices are recommended on all polyphase installations to protect the installation in case of phase reversal or loss of one phase.

SECTION 9
CHARACTER OF SERVICE – VOLTAGE, FREQUENCY AND PHASE
(continued)

F. Load Fluctuation and Balance

1. Interference with Service: The Company reserves the right to refuse to supply loads of a character that may seriously impair service to any other Customers. In the case of hoist or elevator motors, welding machines, furnaces and other installations of like character where the use of electricity is intermittent or subject to violent fluctuations, the Company may require the Customer to provide at the Customer's own expense suitable equipment to reasonably limit those fluctuations.

2. The Company has the right to discontinue electric service to any Customer who continues to use appliances or other devices, equipment and apparatus detrimental to the service after the Company notifies the Customer of his or her causing detriment to the service.

3. Allowable Instantaneous Starting Current Values: The instantaneous starting current (determined by tests or based on limits guaranteed by manufacturers) drawn from the line by any motor must not exceed a value (as determined by the Company) that may be deemed detrimental to the normal operation of the system. If the starting current of the motor exceeds that value, a starter must be used or other means employed to limit the current to the value specified. A reduced voltage starter may be required for polyphase motors.

4. When three-phase service supplied under a power rate includes incidental lighting, the Customer will supply any necessary lighting transformers and arrange its lighting to give a substantially balanced three-phase load.

G. Customer Responsibility for Equipment Used in Receiving Electric Energy

No statement or requirement in these Rules and Regulations can be construed as the assumption of any liability by the Company for any wiring of electrical equipment or the operation of same, installed in, upon, or about the Customer's premises, nor will the Company be responsible for any loss or damage occasioned or caused by the negligence, want of proper care or wrongful act of the Customer, or any of the Customer's agents or employees or licenses on the part of the Customer in installing, maintaining, using, operating, or interfering with any such wiring, machinery or apparatus.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Rules and Regulations

Original Sheet No.: 910
Superseding:

SECTION 10
METER READING

A. Company or Customer Meter Reading

1. The Company may, at its discretion, permit Customer reading of meters.

2. It will be the Company's responsibility to inform the Customer how to properly read his or her meter

3. Where a Customer reads his or her own meter the Company will read the Customer's meter at least once every four (4) months.

4. Where the Company must read the meter every four (4) months, the Customer shall pay Fee No. 3 as set forth in the UNS Electric Statement of Charges for every read.

5. The Company will provide the Customer with postage-paid cards or other methods to report the monthly meter reading to the Company.

6. The Company will specify the timing requirements for the Customer to submit his or her monthly meter reading to conform to the Company's billing cycle.

7. Meter readings will be scheduled for periods of not less than twenty-five (25) days or more than thirty-five (35) days. In the event the Customer fails to submit a reading within this ten (10) day period, the Company may issue the Customer an estimated bill.

8. In the event the Customer fails to submit monthly reads as designated above, the Company may estimate the usage for up to three (3) months.

9. The Company and the Customer shall mutually agree on a method to submit meter reads.

10. Where the Customer is providing their own meter reads, the Customer is responsible for all applicable charges as calculated from the point the Company last read the Customer's meter.

11. Meters will be read monthly on as close to the same day as practical.

B. Measuring of Service

1. All energy sold to Customers and all energy consumed by the Company – except that sold according to fixed charge schedules – will be measured by commercially acceptable measuring devices owned and maintained by the Company. This provision will not apply where it is impractical to install meters, such as street lighting or security lighting, or where otherwise authorized by the ACC.

2. When there is more than one meter at a location, the metering equipment will be so tagged or plainly marked as to indicate the circuit metered or metering equipment in accordance with Subsection 3.C.9.

SECTION 10
METER READING
(continued)

3. Meters which are not direct reading will have the multiplier plainly marked on the meter.

4. The Company may employ meter reading technology that records interval data and displays total consumption.

5. Metering equipment will not be set "fast" or "slow" to compensate for supply transformer or line losses.

C. Customer-Requested Rereads

1. The Company will, at the request of a Customer, reread that Customer's meter within ten (10) business days after that request by the Customer.

2. Any reread may be charged to the Customer, at a rate set forth as Fee No. 2 in the UNS Electric Statement of Charges, if the original reading was not in error.

3. When a reading is found to be in error, the Company will not charge the Customer for the reread.

D. Access to Customer Premises

The Company will at all times have the right of safe ingress to and egress from the Customer's premises at all reasonable hours for any purpose reasonably connected with the Company's property used in furnishing service and the exercise of any and all rights secured to it by law or these Rules.

E. Meter Testing and Maintenance

1. The Company will replace any meter found to be damaged or associated with an inquiry into its accuracy, whether initiated by the Customer or Company, and which has been in service for more than sixteen years. Replaced meters will be tested for accuracy and will be acceptable if found to have an error margin within plus or minus three percent ($\pm$3%).

2. The Company will file an annual report with the Commission summarizing the results of meter maintenance and testing program for that year. At a minimum, the report should include the following data:

   a. Total number of meters tested at Company initiative or upon Customer request; and

   b. Number of meters tested that were outside the acceptable error allowance of $\pm$3%.

SECTION 10
METER READING
(continued)

F. Customer-Requested Meter Tests

1. The Company will test a meter upon Customer request and the Company will be authorized to charge the Customer for the meter test. The charge for the meter test is set forth as Fee No. 7 in the UNS Electric Statement of Charges. However, if the meter is found to be in error by more than three percent (3%), no meter testing fee will be charged to the Customer.

G. Demand

1. The Customer's demand may be measured by a demand meter, under all Rates involving billings based on demand, unless appropriate investigation or tests indicate that the Customer's demand will not be such as to require a demand meter for correct application of the Rate. In cases where billings under a Rate requiring determination of the Customer's demand must be made before a demand meter can be installed, these billings may be made on an estimated demand basis pending installation of the demand meter. Billings made on the basis of estimated demand; however, will be appropriately adjusted, if actual demand recorded after demand meter is installed is greater or less than those estimated demand.

2. Demand meters may be installed at any metering location if the nature of the Customer's equipment and operation indicates that a demand meter is required for correct application of the rate schedule.

3. All demands used for billing purposes will be recorded or computed to the nearest whole kW.

H. Automated Meter Opt-Out

Residential Service (RES-01) Customers may request meters that do not transmit data wirelessly and the Company will accommodate such requests to the extent practicable. The charge for the Special Meter Reading Fee is set forth as Fee No. 3 in the UNS Electric Statement of Charges. The charge for the Automated Meter Opt-Out Set-Up Fee is set forth as Fee No. 6 in the UNS Electric Statement of Charges.

SECTION 11
BILLING AND COLLECTIONS

A. Frequency and Estimated Bills

1. The Company will bill monthly for services rendered. Meter readings will be scheduled for periods of not less than twenty-five (25) days or more than thirty-five (35) days.

2. If the Company is unable to obtain the meter read on the scheduled meter read date, the Company will estimate the consumption for the billing period as set forth in the Company's Bill Estimation Methodologies Tariff.

3. Estimated bills will be issued only under the following conditions:

   a. Failure of a Customer who reads his or her own meter to deliver his or her meter reading card to the Company in accordance with the requirements of the billing cycle.

   b. Severe weather conditions which prevent the Company from reading the meter.

   c. Circumstances that make it dangerous or unnecessarily difficult to read the meter. These circumstances include, but are not limited to, locked gates, blocked meters, vicious or dangerous animals, or any force majeure condition as listed in Subsection 8.E.4.

   d. When an electronic meter reading is obtained, but the data cannot be transferred to a Customer Information System.

   e. A meter failure or malfunction with no reliable information retained by the meter.

   f. A failure of the meter communication network preventing receipt of reliable information.

   g. Meter tampering or energy diversion results in a lack of accurate metered consumption information.

   h. In the event the Customer fails to submit the reading within the designated ten (10) day meter reading window.

   i. In the event the Customer fails to submit monthly reads as designated above, the Company may estimate the usage for up to three (3) months.

4. After the second consecutive month of estimating the Customer's bill, the Company will attempt to secure an accurate reading of the meter.

5. Failure on the part of the Customer to comply with a reasonable request by the Company for access to its meter may lead to the discontinuance of service.

6. Each bill based on estimated usage will indicate that it is an estimated bill.

7. Estimates due to equipment malfunctions may exceed two months if the malfunction could not be reasonably discovered and/or corrected before additional bills were estimated.

8. A bill is not considered an estimated bill when the end read is based on an actual read.

SECTION 11
BILLING AND COLLECTIONS
(continued)

B. Combining Meters, Minimum Bill Information

1. Each meter at a Customer's premises will be considered separately for billing purposes, and the readings of two (2) or more meters will not be combined unless otherwise provided for in the Company's Rates.

2. Each bill for residential service will contain the following minimum information:

   a. Date and meter reading at the start of billing period or number of days in the billing period;
   b. Date and meter reading at the end of the billing period;
   c. Billing usage and demand (if applicable);
   d. Rate schedule number;
   e. Company's telephone number;
   f. Customer's name;
   g. Service account number;
   h. Amount due and due date;
   i. Past due amount;
   j. Purchased Power Fuel Adjuster Clause cost, where applicable;
   k. Other ACC-approved charges;
   l. All applicable taxes; and
   m. The address for the Arizona Corporation Commission.

C. Billing Terms

1. All bills for electric service are due and payable no later than ten (10) days from the date the bill is rendered. Any payment not received within this time frame will be considered past due.

2. For purposes of this rule, the date a bill is rendered may be evidenced by:

   a. The postmark date for bills sent via U.S. Postal Service; or
   b. The mailing date; or
   c. The billing date shown on the bill (however, the billing date will not differ from the postmark or mailing date by more than two (2) days).
   d. An Electronic Bill will be considered rendered at the time it is electronically sent to the Customer.

SECTION 11
BILLING AND COLLECTIONS
(continued)

3. All past due bills for electric service are due and payable within fifteen (15) days. Any payment not received within this timeframe will be considered delinquent and will be issued a suspension of service notice. For Customers under the jurisdiction of a bankruptcy court, a more stringent payment or prepayment schedule may be required, if allowed by that court.

4. All delinquent bills for which a valid payment has not been received within five (5) days will be subject to the provisions of the Company's termination procedures.

5. The amount of the late payment penalty as set forth as Fee No. 10 in the UNS Electric Statement of Charges will not exceed one and one-half percent (1.5%) of the delinquent bill, applied on a monthly basis.

6. All payments must be made by a payment method authorized by the Company.

7. A bill will be rendered in a form prescribed by the Company. If the Customer requests a bill in a form other than the one prescribed by the Company, the Company in its sole discretion may consider such request and charge the Customer any associated costs.

D. Applicable Rates, Prepayment, Failure to Receive, Commencement Date, Taxes

1. Each Customer will be billed under the applicable tariff indicated in the Customer's application for service.

2. Customers may pay for electrical service by making advance payments.

3. Failure to receive bills or notices that have been properly placed in the U.S. Postal Service or posted electronically will not prevent those bills from becoming delinquent nor relieve the Customer of his obligations therein.

4. Charges for service commence when the service is installed and connection made, whether used or not.

E. Meter Error Corrections

1. If any meter after testing is found to be more than three percent (3%) in error, either fast or slow, proper correction of the error will be made of previous readings and adjusted bills will be rendered according to the following terms:

   a. For the period of three (3) months immediately preceding the removal of such meter from service for test or from the time the meter was in service since last tested, but not exceeding three (3) months since the meter has been shown to be in error by the test; or

SECTION 11
BILLING AND COLLECTIONS
(continued)

b. From the date the error occurred, if the date of the cause can be definitely fixed. If the Customer has been underbilled, the Company will allow the Customer to repay this difference over the same period of time for which the underbillings occurred. The Customer may be allowed to pay the backbill without late payment penalties, unless there is evidence of meter tampering or energy diversion.

c. If it is determined that the Customer has been overbilled and there is no evidence of meter tampering or energy diversion, the Company will make prompt adjustment or refund in the difference between the original billing and the corrected billing within the next billing cycle.

2. No adjustment will be made by the Company except to the Customer last served by the meter tested.

F. Responsibility for Payment of Bills

1. The Customer is responsible for the payment of bills until service is ordered discontinued and the Company has had reasonable time to secure a final meter reading for those services involving energy usage, or if non-metered services are involved until the Company has had reasonable time to process the disconnect request.

2. When an error is found to exist in the billing rendered to the Customer, the Company shall correct such an error to refund any overbilling and may correct such an error to recover any underbilling. The UNS Electric Bill Estimation Methodologies tariff shall be applied when the Company cannot obtain a complete and valid meter read. Situations that result in an estimated meter read include inclement weather, lack of access to a Customer's meter, energy diversion, labor unavailability and equipment malfunction.

3. Except as specified below, corrected charges for underbillings shall be limited to three (3) months for residential accounts and six (6) months for non-residential accounts.

   a. Where the account is billed on a special contract or non-metered rate, corrected charges for underbillings shall be billed in accordance with the contract or rate requirements and is not limited to three or six months as applicable.

   b. Where service has been established but no bills have been rendered, or a bill is rendered, but shows no consumption, corrected charges for underbillings shall go back to the date service was established.

   c. Where there is evidence of meter tampering or energy diversion, corrected charges for underbillings shall go back to the date meter tampering or energy diversion began, as determined by the Company.

   d. Where lack of access to the meter (caused by the Customer) has resulted in estimated bills, corrected charges for underbillings shall go back to the billing month of the last Company obtained meter read date.

SECTION 11
BILLING AND COLLECTIONS
(continued)

G. Returned Payments

1. The Company will be allowed to recover a fee, as set forth as Fee No. 9 in the UNS Electric Statement of Charges, for each instance where a Customer tenders payment for electric service with a payment returned unpaid. This fee will also apply when an electronic funds transfer ("EFT") is denied for any reason.

2. When the Company is notified by the Customer's bank or other financial institution that a payment has been returned unpaid, or denied for any reason, the Company may require the Customer to make payment in cash, by money order or other approved methods which guarantee the Customer's payment to the Company.

3. A Customer, who tenders a payment which is returned unpaid, regardless of the reason or method used to pay, will not be relieved of the obligation to render payment to the Company under the original terms of the bill nor defer the Company's provision for termination of service for nonpayment of bills.

4. A Customer with two (2) returned payments within a twelve (12) month period may be required to pay with guaranteed funds, (i.e., cash, money order, or other approved methods for any subsequent billing for twelve (12) months.

H. Budget Billing Plan

1. The Company may, at its option, offer its Customers a budget billing plan.

2. The Company will provide, upon Customer request, an estimate of the Customer's budget billing amount for a twelve-month period based upon:

   a. Customer's actual consumption history, which may be adjusted for abnormal conditions such as weather variations;

   b. For new Customers, the Company will estimate consumption based on the Customer's anticipated load requirements; or

   c. The Company's Rates approved by the ACC applicable to that Customer's class of service.

3. The Company will provide the Customer, upon Customer request, a concise explanation of how the budget billing estimate was developed, the impact of budget billing on a Customer's monthly bill, and the Company's right to adjust the Customer's billing for any variation between the Company's estimated billing and actual billing.

SECTION 11
BILLING AND COLLECTIONS
(continued)

4. For those Customers being billed under a budget billing plan, the Company will show, at a minimum, the following information on the Customer's monthly bill:

   a. Actual consumption;

   b. Amount due for actual consumption;

   c. Budget billing amount due; and

   d. Accumulated variation in actual versus budget billing amount.

5. The Company may adjust the Customer's budget billing in the event the Company's estimate of the Customer's usage and/or cost varies significantly from the Customer's actual usage and/or cost. This review to adjust the amount of the budget billing may be initiated by the Company or the Customer.

6. While on the budget billing plan, the Customer shall pay the monthly plan amount , notwithstanding the current charges shown on the bill.

7. Any other charges incurred by the Customer shall be paid when due in addition to the monthly plan amount.

8. Interest will not be charged to the Customer on accrued debit balances nor paid by the Company on accrued credit balances.

I. Deferred Payment Plan

1. The Company may, prior to termination of service, offer to qualifying Customers a deferred payment plan for the Customer to retire unpaid delinquent bills for electric service.

2. Each deferred payment agreement entered into between the Company and the Customer – due to the Customer's inability to pay an outstanding bill in full – will specify that service will not be discontinued if:

   a. Customer agrees to pay a reasonable amount of the outstanding bill at the time the parties enter into the deferred payment agreement;

   b. Customer agrees to pay all future bills for electric service in accordance with the Company's Rates; and

   c. Customer agrees to pay a reasonable portion of the remaining outstanding balance in installments over a period not to exceed three (3) months.

SECTION 11
BILLING AND COLLECTIONS
(continued)

3. For the purpose of determining a reasonable installment payment schedule, under these rules, the Company and the Customer will give consideration to the following conditions:

   a. The size of the delinquent account;

   b. The Customer's ability to pay;

   c. The Customer's payment history;

   d. The length of time that the debt has been outstanding;

   e. The circumstances that resulted in the debt being outstanding; and

   f. Any other relevant factors related to the circumstances of the Customer.

4. Any Customer who desires to enter into a deferred payment agreement must do so before the Company's scheduled termination date for nonpayment of bills. The Customer's failure to execute a deferred payment agreement prior to the scheduled service termination date will not prevent the Company from terminating service for nonpayment.

5. Deferred payment agreements may be in writing and may be signed by the Customer and an authorized Company representative.

6. 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.

7. If a Customer has not fulfilled the terms of a deferred payment agreement, the Company will have the right to disconnect service pursuant to the Company's Termination of Service Rules (Section 12) and, under these circumstances, it will not be required to offer subsequent negotiation of a deferred payment agreement prior to disconnection.

J. Change of Occupancy

1. To order service to be discontinued or to change occupancy, the Customer must give the Company at least three (3) business days advance notice via the website, e-mail, in writing or by telephone.

2. The outgoing Customer will be responsible for all electric services provided and/or consumed up to the scheduled turn-off date.

3. The outgoing Customer or property owner, in the case of a known landlord/tenant situation, is responsible for providing access to the meter so that the Company may obtain a final meter reading. If access is unavailable, due to the action or inaction of the Customer or property owner, the outgoing Customer or owner/landlord will be responsible for the services consumed until such time as access is provided and services can be disconnected.

SECTION 11
BILLING AND COLLECTIONS
(continued)

K. Electronic Billing

1. Electronic Billing is an optional billing service whereby Customers may elect to receive, view, and pay their bills electronically. Electronic Billing includes the "UES e-bill" service with a no-fee payment option. The Company may modify its Electronic Billing services from time to time. A Customer electing an electronic billing service may receive an electronic bill in lieu of a paper bill.

2. Customers electing an electronic billing service may be required to complete additional forms and agreements.

3. Electronic Billing may be discontinued at any time by the Company or the Customer.

4. An Electronic Bill will be considered rendered at the time it is electronically sent to the Customer. Failure to receive bills or notices which have been properly sent by an Electronic Billing system does not prevent these bills from becoming delinquent and does not relieve the Customer of the Customer's obligations therein.

5. Any notices that the Company is required to send to a Customer who has elected an Electronic Billing service may be sent by electronic means at the option of the Company.

6. Except as otherwise provided in this subsection, all other provisions of the Company's Rules and Regulations and other applicable Rates are applicable to Electronic Billing.

7. The Customer must provide the Company with a current email address for electronic bill delivery. If the Electronic Bill is electronically sent to the Customer at the email address that Customer provided to the Company, then the Electronic Bill will be considered properly sent. Further, the Customer will be responsible for updating the Company with any changes to this email address. Failure to do so will not excuse the Customer from timely paying the Company for electric service.

L. Collections

1. All unpaid closed accounts may be referred to a collection agency for collections.

2. If a collection agency referral is warranted for collection of unpaid final bills, Customer will be responsible for associated collection agency fees assessed. If the unpaid bill is referred to a credit bureau, the Company will not be held responsible to notify the Credit Bureau of any payment status.

M. Refunds

Customers will not be eligible for refunds, rebates or other Company program payments if the Customer has a delinquent Company balance.

SECTION 11
BILLING AND COLLECTIONS
(continued)

N. Refund of Credit Balance Following Discontinuance of Service

Upon discontinuance of service, the Company shall refund the Customer any credit balance remaining on the account. With the consent of the Customer (when available), any credit balance remaining on the account that is less than $5.00, shall be donated to a low-income assistance program to be determined by the Company or as may be required by law.

SECTION 12
TERMINATION OF SERVICE

A. Please refer to the Arizona Administrative Code R14-2-211.A.

B. Termination of Service Without Notice

1. The Company may disconnect electric service without advance written notice under the following conditions:

   a. The existence of an obvious hazard to the safety or health of the Customer or the general population or the Company's personnel or facilities;

   b. The Company has evidence of meter tampering or fraud; or

   c. The Company has evidence of unauthorized resale or use of electric service; or

   d. Customer makes payment to avoid/stop disconnection for non-payment with a dishonored or fraudulent payment. The Company will not be required to restore service until the repayment of those funds and all other delinquent amounts are paid by cash, money order, cashier's check, certified funds or verified electronic payment; or

   e. Customer makes payment to reconnect service with a dishonored or fraudulent payment. The Company will not be required to restore service until the repayment of those funds and all other delinquent amounts are paid by cash, money order, cashier's check, certified funds or verified electronic payment; or

   f. Failure of a Customer to comply with the curtailment procedures imposed by the Company during supply shortages.

2. The Company will not be required to restore service until the conditions that led to the termination have been corrected to the satisfaction of the Company.

3. The Company will maintain a record of all terminations of service without notice. This record will be maintained for a minimum of one (1) year and will be available for inspection by the ACC.

C. Termination of Service With Notice

1. The Company may disconnect service to any Customer for any reason stated below, provided that the Company has met the notice requirements described in subsection 12.D. below:

   a. Customer violation of any of the Company's Rates;

   b. Failure of the Customer to pay a delinquent bill for electric service;

   c. Failure of a prior Customer to pay a delinquent bill for electric service where the prior Customer continues to reside on the premise;

   d. Failure of the Customer to meet agreed-upon deferred payment arrangements;

SECTION 12
TERMINATION OF SERVICE
(continued)

e. Failure to meet or maintain the Company's deposit requirements;

f. Failure of the Customer to provide the Company reasonable safe access to its equipment and property;

g. Customer breach of a written contract for service between the Company and Customer;

h. Returned or invalid payment;

i. When necessary for the Company to comply with an order of any governmental agency having jurisdiction;

j. When a hazard exists which is not imminent, but in the opinion of the Company, it may cause property damage;

k. Customer facilities that do not comply with Company requirements or specifications;

l. Failure to provide or retain rights-of-way or easements necessary to serve the Customer;

m. The Company learns of the existence of any condition in Section 3.D., Grounds for Refusal of Service.

2. The Company will maintain a record of all terminations of service with notice. This record will be maintained for one (1) year and be available for ACC inspection.

D. The Company will not be obligated to renotify the Customer of the termination of service, even if the Customer – after receiving the required termination of service notification – has made payment, yet the payment is returned within three (3) to five (5) business days of receipt for any reason. The original notification will apply.

E. Termination Notice Requirements

1. The Company will not terminate service to any of its Customers without providing advance written notice to the Customer of the Company's intent to disconnect service, except under these conditions specified in subsection 12.A. where advance written notice is not required.

2. This advance written notice will contain, at a minimum, the following information:

a. The name of the person whose service is to be terminated and the address where service is being rendered;

b. The Company's Rate(s) that was violated and explanation of the violation or the amount of the bill that the Customer has failed to pay in accordance with the payment policy of the Company, if applicable;

c. The date on or after which service may be terminated;

d. A statement advising the Customer to contact the Company at a specific phone number for information regarding any deferred payment or other procedures that the Company may offer or to work out some mutually agreeable solution to avoid termination of the Customer's service; and;

SECTION 12
TERMINATION OF SERVICE
(continued)

e. A statement advising the Customer that the Company's stated reason(s) for the termination of services may be disputed by contacting the Company at a specific address or phone number, advising the Company of the dispute and making arrangements to discuss the cause for termination with a responsible employee of the Company in advance of the scheduled date of termination. The responsible employee will be empowered to resolve the dispute and the Company will retain the option to terminate service after affording this opportunity for a meeting and concluding that the reason for termination is just and advising the Customer of his or her right to file a complaint with the ACC.

3. Where applicable, a copy of the termination notice will be simultaneously forwarded to designated third parties.

F. Timing of Terminations with Notice

1. The Company will give at least five (5) days advance written notice prior to the termination date. For Customers under the jurisdiction of a bankruptcy court, a shorter notice may be provided, if permitted by the court.

2. This notice will be considered to be given to the Customer when a copy of the notice is left with the Customer or posted first class via the U.S. Postal Service, addressed to the Customer's last known address.

3. If, after the period of time allowed by the notice has elapsed and the delinquent account has not been paid nor arrangements made with the Company for the payment of the bill – or in the case of a violation of the Company's rules the Customer has not satisfied the Company that this violation has ceased – then the Company may terminate service on or after the day specified in the notice without giving further notice.

4. The Company will have the right (but not the obligation) to remove any or all of its property installed on the Customer's premises upon the termination of service.

G. Landlord/Tenant Rule

In situations where service is rendered at an address different from the mailing address of the bill or where the Company knows that a landlord/tenant relationship exists and that the landlord is the Customer of the Company, and where the landlord as a Customer would otherwise be subject to disconnection of service, the Company will not disconnect service until the following actions have been taken:

1. Where it is feasible to so provide service, the Company will offer the occupant the opportunity to subscribe for service in the occupant's own name. If the occupant then declines to so subscribe, the Company may disconnect service pursuant to the rules.

2. The Company will not attempt to recover from a tenant or condition service to a tenant with the payment of any outstanding bills or other charges due upon the outstanding account of the landlord.

SECTION 12
TERMINATION OF SERVICE
(continued)

H. 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 a 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.

SECTION 13
RECONNECTION OF SERVICE

When service has been discontinued for any of the reasons set forth in these Rules and Regulations, the Company will not be required to restore service until the following conditions have been met by the Customer:

A. Where service was discontinued without notice:

1. The hazardous condition must be removed and the installation will conform to accepted standards.
2. All bills for service and/or applicable investigative costs due the Company by reason of fraudulent or unauthorized use, diversion or tampering must be paid and a deposit to guarantee the payment of future bills may be required.
3. Required arrangements for service must be made.

B. Where service was discontinued with notice:

1. The Customer must make arrangements for the payment of all bills and these arrangements must be satisfactory to the Company.
2. The Customer must furnish a satisfactory guarantee to pay all future bills.
3. The Customer must correct any and all violations of these Rules and Regulations.

SECTION 14
ADMINISTRATIVE AND HEARING REQUIREMENTS

A. Customer Service Complaints

1. The Company will make a full and prompt investigation of all service complaints made by its Customers, either directly or through the ACC.

2. The Company will respond to the complainant and/or the ACC representative within five (5) business days as to the status of the Company's investigation of the complaint.

3. The Company will notify the complainant and/or the ACC representative of the final disposition of each complaint. Upon request of the complainant or the ACC representative, the Company will report the findings of its investigation in writing.

4. The Company will inform the Customer of his right of appeal to the ACC.

5. The Company will keep a record of all written service complaints received that must contain, at a minimum, the following data:

   a. Name and address of complainant;

   b. Date and nature of the complaint;

   c. Disposition of the complaint; and

   d. A copy of any correspondence between the Company, the Customer, and/or the ACC.

6. This record will be maintained for a minimum period of one (1) year and will be available for inspection by the ACC.

B. Customer Bill Disputes

1. Any Customer who disputes a portion of a bill rendered for electric service must pay the undisputed portion of the bill and notify the Company's designated representative that any unpaid amount is in dispute prior to the delinquent date of the bill.

SECTION 14
ADMINISTRATIVE AND HEARING REQUIREMENTS
(continued)

2. Upon receipt of the Customer notice of dispute, the Company will:

   a. Notify the Customer within five (5) business days of the receipt of a written dispute notice;

   b. Initiate a prompt investigation as to the source of the dispute;

   c. Withhold disconnection of service until the investigation is completed and the Customer is informed of the results;

   d. Upon request of the Customer the Company will report the results of the investigation in writing; and

   e. Inform the Customer of his right of appeal to the ACC.

3. Once the Customer has received the results of the Company's investigation, the Customer will submit payment within five (5) business days to the Company for any disputed amounts. Failure to make full payment will be grounds for termination of service.

C. ACC Resolution of Service and/or Bill Disputes

1. In the event a Customer and the Company cannot resolve a service and/or bill dispute, the Customer will file a written statement of dissatisfaction with the ACC. By doing this, the Customer will be deemed to have filed an informal complaint against the Company.

2. Within thirty (30) days of the receipt of a written statement of Customer dissatisfaction related to a service or bill dispute, a designated representative of the ACC will attempt to resolve the dispute by correspondence and/or telephone with the Company and the Customer. If resolution of the dispute is not achieved within twenty (20) days of the ACC representative's initial effort, the ACC will then hold an informal hearing to arbitrate the resolution of the dispute. The informal hearing will be governed by the following rules:

   a. Each party may be represented by legal counsel, if desired;

   b. Every informal hearing may be recorded or held in the presence of a stenographer;

   c. All parties will have the opportunity to present written or oral evidentiary material to support the positions of the individual parties;

   d. All parties and the ACC's representative will be given the opportunity for cross-examination of the various parties; and

SECTION 14
ADMINISTRATIVE AND HEARING REQUIREMENTS
(continued)

e. The ACC's representative will render a written decision to all parties within five (5) business days after the date of the informal hearing. This written decision of the ACC's representative is not binding on any of the parties and the parties will still have the right to make a formal complaint to the ACC.

3. The Company may implement normal termination procedures if the Customer fails to pay all bills rendered during the resolution of the dispute by the ACC.

4. The Company will maintain a record of written statements of dissatisfaction and their resolution for a minimum of one (1) year and make these records available for ACC inspection.

Exhibit DAS-2

REDLINED

UniSourceEnergy SERVICES

TABLE OF CONTENTS

SECTION 1
APPLICABILITY OF RULES AND REGULATIONS AND DESCRIPTION OF SERVICE

A. UNS Electric, Inc. ("Company") is an electric utility operating within portions of the state of Arizona. The Company will provide service to any person, institution or business located within its service area in accordance with the provisions of its Rates and the terms and conditions of these Rules and Regulations.

B. All electricity delivered to any Customer is for the sole use of that Customer on that Customer's premises only. Electricity delivered by the Company will not be redelivered or resold, or the use thereof by others permitted unless otherwise expressly agreed to in writing by the Company. However, those Customers purchasing electricity for redistribution to the Customer's own tenants (only on the Customer's premises) may separately meter each tenant distribution point for the purpose of prorating the Customer's actual purchase price of electricity delivered among the various tenants on a per unit basis.

C. These Rules and Regulations will apply to all electricity service furnished by the Company to its Customers.

D. These Rules and Regulations are part of the Company's Rates on file with, and duly approved by, the Arizona Corporation Commission. These Rules and Regulations will remain in effect until modified, amended, or deleted by order of the ACC. No employee, agent or representative of the Company is authorized to modify the Company rules.

E. These Rules and Regulations will be applied uniformly to all similarly situated Customers.

F. In case of any conflict between these Rules and Regulations and the Arizona Corporation Commission's rules, these Rules and Regulations will apply.

G. Whenever the Company and an Applicant or a Customer are unable to agree on the terms and conditions under which the Applicant or Customer is to be served, or are unable to agree on the proper interpretation of these Rules and Regulations, either party may request assistance from the Consumer Services Section of the Utilities Division of the ACC. The Applicant or Customer also has the option to file an application with the ACC for a proper order, after notice and hearing.

H. The Company's supplying electric service to the Customer and the acceptance thereof by the Customer will be deemed to constitute an agreement by and between the Company and the Customer for delivery, acceptance of and payment for electric service under the Company's Rules and Regulations and applicable Rates.

SECTION 2
DEFINITIONS

A. In these Rules and Regulations, the following definitions will apply unless the context requires otherwise:

1. Actual Cost: The cost incurred by the Company for labor, materials and equipment including the cost of overheads.

2. Advance in Aid of Construction ("Advance"): Funds provided to the utility by the Applicant under the terms of a line extension agreement, the value of which may be refunded.

3. Applicant: A person requesting the Company to supply electric service.

4. Application: A request to the Company for electric service, as distinguished from an inquiry as to the availability or charges for such service.

5. Arizona Corporation Commission ("ACC" or "Commission"): The regulatory authority of the State of Arizona having jurisdiction over public service corporations operating in Arizona.

6. Billing Month: The period between any two (2) regular readings of the Company's meters at approximately thirty (30) day intervals.

7. Billing Period: The time interval between two (2) consecutive meter readings that are taken for billing purposes.

8. Company: UNS Electric, Inc. acting through its duly authorized officers or employees within the scope of their respective duties.

9. Contiguous Site: A single site not separated by private or public property, or public street, or right of way and operated as one integral unit under the same name and as a part of the same business.

10. Contributions in Aid of Construction ("Contribution"): Funds provided to the Company by the Applicant under the terms of a line extension agreement and/or service connections tariff, the value of which is not refundable.

11. Curtailment Priority: The order in which electric service is to be curtailed to various classifications of Customers, as set forth in the Company's filed Rates.

12. Customer: The person(s) or entity(ies) in whose name service is rendered, as evidenced by the request for electric service by the Applicant(s), or by the receipt and/or payment of bills regularly issued in the Customer's name regardless of the identity of the actual user of the service.

13. Customer Charge: The amount the Customer must pay the Company for the availability of electric service, excluding any electricity used, as specified in the Company's Rates.

14. Day: Calendar day.

SECTION 2
DEFINITIONS
(continued)

15. Demand: The rate at which power is delivered during any specified period of time. Demand may be expressed in kilowatts, kilovolt-amperes, or other suitable units.

16. Developer: One or more natural or artificial entities that own, improve, or remodel real estate.

17. Distribution Lines: The Company lines operated at distribution voltage, which are constructed along public roadways or other bona fide rights-of-way, including easements on Customer's property.

18. Electronic Billing: Optional billing service whereby Customers may elect to receive, view and pay their bills electronically.

19. Energy: Electric energy, expressed in kilowatt-hours.

20. Illness: A medical ailment or sickness for which a residential Customer obtains a verified document from a licensed medical physician stating the nature of the illness and that discontinuance of service would be especially dangerous to the Customer's health.

21. Interruptible Electric Service: Electric service that is subject to interruption as specified in the Company's Rate.

22. Kilowatt ("kW"): A unit of power equal to 1,000 watts.

23. Kilowatt-hour ("kWh"): Electric energy equivalent to the amount of electric energy delivered in one hour when delivery is at a constant rate of one (1) kilowatt.

24. Law: Any statute, rule, order or requirement established and enforced by government authorities.

25. Line Extension: The lines and equipment necessary to extend the electric distribution system of the Company to provide service to additional Customers.

26. Master Meter: A meter for measuring or recording the flow of electricity that has passed through it at a single location where said electricity is distributed to tenants or occupants for their usage.

27. Megawatt ("MW"): A unit of power equal to 1,000,000 watts.

28. Meter: The instrument for measuring and indicating or recording the flow of electricity that has passed through it.

29. Meter Tampering: A situation where a meter has been illegally altered. Common examples are meter bypassing, use of magnets to slow the meter recording, and broken meter seals.

30. Minimum Charge: The amount the Customer must pay for the availability of electric service, including an amount of usage, as specified in the Company's Rates.

SECTION 2
DEFINITIONS
(continued)

31. Month: The period between any two (2) regular readings of the Company's meters at approximately thirty (30) day intervals.

32. On-Site Generation: Any and all power production generated on or adjacent to a Customer's property that is controlled, utilized, sold, or consumed by that Customer or its agent.

33. Permanent Customer: A Customer who is a tenant or owner of a service location who applies for and receives permanent electric service.

34. Permanent Service: Service which, in the opinion of the Company, is of a permanent and established character. The use of electricity may be continuous, intermittent, or seasonal in nature.

35. Person: Any individual, partnership, corporation, governmental agency, or other organization operating as a single entity.

36. Point of Delivery: In all cases, unless otherwise specified, "point of delivery" is the location on the Customer's building, structure, or premises where all wires, conductors, or other current-carrying devices of the Customer join or connect with wires, conductors, or other current-carrying devices of the Company. The Company will determine the point of delivery in accordance and based on the specific design specifications, relevant and appropriate technical standards and specifications, Rates and construction standards as applicable to the specific situation. Location and type of metering facilities will be determined by the Company and may or may not be at the same location as the point of delivery.

37. Power: The rate of generating, transferring and/or using electric energy, usually expressed in kilowatts.

38. Power Factor: The ratio of real or active power ("kW") to apparent or reactive power ("kVA").

39. Premises: All of the real property and apparatus employed in a single enterprise on an integral parcel of land undivided by public streets, alleys or railways.

40. Primary Service and Metering: Service supplied directly from the Company's high voltage distribution or transmission lines without prior transformation to a secondary level.

41. Prorate: To divide, distribute, or assess proportionately.

42. Rates: The charge(s), related term(s) and conditions of the Company's Tariffs.

43. Residential Subdivision ~~Development~~: Any tract of land which has been divided into four or more contiguous lots with an average size of one acre or less for use for the construction of residential buildings or permanent mobile homes for either single or multiple occupancy.

SECTION 2
DEFINITIONS
(continued)

44. Residential Use: Service to Customers using electricity for domestic purposes such as space heating, air conditioning, water heating, cooking, clothes drying, and other residential uses and includes use in apartment buildings, mobile home parks, and other multiunit residential buildings.

45. Revenue: Delivery charge, power supply charge, demand charge, and PPFAC charge collected from Customer.

46. Rules and Regulations or Company Rules: These Rules and Regulations, which are a part of the Company's Tariffs and Rates.

47. Secondary Service: Service supplied at secondary voltage levels from the load side of step-down transformers connected to the Company's high voltage distribution lines.

48. Service Area: The territory in which the Company has been granted a certificate of convenience and necessity and is authorized by the ACC to provide electric service.

49. Service Drop: The overhead service conductors from the last Company-owned pole or other aerial support to and including the splices, if any, connecting to the Customer's service entrance conductors at a building or other structure.

50. Service Establishment Charge: The charge as specified in the Company's Rates, which covers the cost of establishing a new account.

51. Service Line: The line extending from a distribution line or transformer to the Customer's premises or point of delivery.

52. Service Reconnection Charge: The charge as specified in the Company's Rates which must be paid by the Customer prior to reestablishment of electric service each time the electricity is disconnected for nonpayment or whenever service is discontinued for failure otherwise to comply with the Company's Rates or Rules.

53. Service Reestablishment Charge: A charge as specified in the Company's Rates for service in the same location where the same Customer had ordered a service disconnection within the preceding twelve (12) month period.

54. Single Family Dwelling: A house, an apartment, or a mobile home permanently affixed to a lot, or other permanent residential unit which is used as a permanent home.

55. Single-Phase Service: Two (2) or Three (3) wire service ~~(usually 120/240 volts)~~.

56. Tariffs: The terms and conditions of the services offered by the Company, including a schedule of the Rates and charges for those services.

SECTION 2
DEFINITIONS
(continued)

57. Temporary Service: Service to premises or enterprises which are temporary in character, or where it is known in advance that the service will be of limited duration. Service which, in the opinion of the Company, is for operations of a speculative character is also considered temporary service.

58. Three-Phase Service: Four (4) wire service ~~(usually 120/208 volts)~~.

59. Weather Especially Dangerous to Health: That period of time commencing with the scheduled termination date when the local weather forecast, as predicted by the National Oceanographic and Administration Service, indicates that the temperature will not exceed thirty-two (32) degrees Fahrenheit for the next day's forecast. The ACC may determine that other weather conditions are especially dangerous to health as the need arises.

SECTION 3
ESTABLISHMENT OF SERVICE

A. Information from New Applicants

1. The Company may obtain the following minimum information from each application for service:

   a. Name or names of Applicant(s);

   b. Service address or location and telephone number;

   c. Billing address/telephone number, if different than service address;

   d. Social Security Number or Driver's License number and date of birth to be consistent with verifiable information on legal identification;

   e. Address where service was provided previously;

   f. Date Applicant will be ready for service;

   g. Statement of whether premises have been supplied with electric service previously;

   h. Purpose for which service is to be used;

   i. Statement of whether Applicant is owner or tenant of or agent for the premises;

   j. Information concerning the energy and demand requirements of the Customer; and

   k. Type and kind of life-support equipment, if any, used by the Customer or at the service address.

2. Where service is requested by two (2) or more individuals, the Company will have the right to collect the full amount owed to the Company from any one of the Applicants.

3. The supplying of electric service by the Company and the Customer's acceptance of that electric service will be deemed to constitute an agreement by and between the Company and the Customer for delivery, acceptance of and payment for electric service under the Company's applicable Rates, and Rules and Regulations.

4. The term of any agreement not otherwise specified will become operative on the day the Customer's installation is connected to the Company's facilities for the purpose of taking electric energy.

5. The Company may require a written contract with special guarantees from Applicants whose unusual characteristics of load or location would require excessive investment in facilities or whose requirements for service are of a special nature.

6. Signed contracts may be required for service to commercial and industrial establishments. No contract or any modification of the contract will be binding upon the Company until executed by a duly authorized representative of the Company.

7. Where an occupant of the premises who owes a debt to the Company, but is not the Applicant or the Customer, the occupant shall also be jointly and severally liable for the bills rendered to the premises.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

B. Deposits

1. The Company may require from any present or prospective Customer a deposit to guarantee payment of all bills. This deposit may be retained by the Company until service is discontinued and all bills have been paid; except as provided in Subsection B.3. below. Upon proper application by the Customer, the Company will then return said deposit, together with any unpaid interest accrued thereon from the date of commencement of service or the date of making the deposit, whichever is later. The Company will be entitled to apply said deposit together with any unpaid interest accrued thereon, to any indebtedness for the same class of service owed to the Company for electric service furnished to the Customer making the deposit. When said deposit has been applied to any such indebtedness, the Customer's electric service may be discontinued until all such indebtedness of the Customer is paid and a like deposit is again made with the Company by the Customer. No interest will accrue on any deposit after discontinuance of the service to which the deposit relates.

   The Company will not require a deposit from a new Applicant for residential service if the Applicant is able to meet any of the following requirements:

   a. The Applicant has had service of a comparable nature with the Company within the past two (2) years and was not delinquent in payment ~~more than~~ twice during the last twelve (12) consecutive months of service or was not disconnected for nonpayment; or

   b. The Applicant can produce a letter of credit or verification from an electric utility where service of a comparable nature was last received by Applicant, which states Applicant had a timely payment history at time of service discontinuation; or

   c. Instead of a deposit, the Company receives deposit guarantee notification from a social or governmental agency acceptable to the Company. A surety bond may be provided as security for the Company in an amount equal to the required deposit.

~~2. The Company may issue a non-assignable, non-negotiable receipt to the Applicant for the deposit. The inability of the Customer to produce his or her receipt will in no way impair the Customer's right to receive a refund of the deposit which is reflected on the Company records.~~

~~3.~~2. Cash deposits held by the Company twelve (12) months or longer will earn interest at the established one-year Treasury Constant Maturities rate, effective on the first business day of each year, as published in the Federal Reserve website.

~~4.~~3. ~~a.~~ Residential Customers – The Company may require a residential Customer to establish or reestablish a deposit if the Customer becomes~~ame~~ delinquent in the payment of ~~three (3)~~two (2) or more bills ~~within a twelve (12) consecutive month period,~~ or has been disconnected from service during the last twelve (12) months.~~, or the Company has a reasonable belief that the Customer is not credit worthy based on a rating from a credit agency utilized by the Company.~~

Deposits or other instruments of credit will automatically expire or be refunded or credited to the Customer's account~~,~~ after twelve (12) consecutive months of service during which time the Customer has not been delinquent ~~more than~~ two (2) times or has not been disconnected for non-payment, unless the Customer has filed bankruptcy in the last twelve (12) months.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

4. ~~b.~~ Non-Residential Customers – The Company may require a non-residential Customer to establish or reestablish a deposit if the Customer becomes delinquent in the payment of two (2) bills or if the Customer has been disconnected for non-payment during the last twelve (12) months, or when the Customer's financial condition may jeopardize the payment of their bill.

Deposits and non-cash deposits on file with the Company will be reviewed ~~or other instruments of credit will automatically expire or be refunded or credited to the Customer's account~~ after twenty-four (24) consecutive months of service and will be returned provided ~~during which~~ the Customer has not been delinquent ~~more than~~ two (2) times or disconnected for non-payment in the most recent twelve (12) month period, unless the Customer's financial condition warrants extension of the deposit.

~~4. The Company may require a Customer to establish or reestablish a deposit if the Customer became delinquent in the payment of three (3) or more bills within a twelve (12) consecutive month period, or has been disconnected from service during the last twelve (12) months, or the Company has a reasonable belief that the Customer is not credit worthy based on a rating from a credit agency utilized by the Company.~~ **[Subsection 3.B.4 has not been deleted; it has been moved to Subsection 3.B.3.]**

5. The Company may review the Customer's usage after service has been connected and adjust the deposit amount based upon the Customer's actual usage.

6. A separate deposit may be required for each meter installed.

7. Residential Customer deposits will not exceed two (2) times that Customer's estimated average monthly bill. Non-residential Customer deposits will not exceed two and one-half (2.5) times that Customer's maximum estimated monthly bill. If actual usage history is available, then that usage, adjusted for normal weather, will be the basis for the estimate.

8. The posting of a deposit will not preclude the Company from terminating service when the termination is due to the Customer's failure to perform any obligation under the agreement for service or any of these Rules and Regulations.

C. Conditions for Supplying Service

The Company reserves the right to determine the conditions under which service will be provided. Conditions for service and extending service to the Customer will be based upon the following:

1. Customer has wired his premises in accordance with the National Electric Code, City, County and/or State codes, whichever are applicable.

2. If the Company determines that there is a reasonable basis to believe that the Customer's premises poses a safety risk to Company employees, then the Company may, at its option, install a meter or facilities with remote connect and/or disconnect capabilities.

~~2.~~

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

3. Customer has installed the meter loop in a suitable location approved by the Company.

4. In the case of a mobile home, the meter loop must be attached to a meter pole or to an approved support.

5. In case of temporary construction service, the meter loop must be attached to an approved support.

6. All meter loop installations must be in accordance with the Company's specifications and located at an outdoor location accessible to the Company.

7. Individual Customers may be required to have their property corner pins and/or markers installed to establish proper right-of-way locations.

8. Developers must have all property corner pins and/or markers installed necessary to establish proper locations to supply electric service to individual lots within subdivisions.

9. Where the installation requires more than one meter for service to the premises, each meter panel must be permanently marked (not painted) by the contractor or Customer to properly identify the portion of the premises being served.

10. The identification will be the same as the apartment, office, etc., served by that meter socket. The identifying marking placed on each meter panel will be impressed into or raised from a tab of aluminum, brass or other approved non-ferrous metal with minimum one-fourth (1/4) inch-high letters. This tag must be riveted to the meter panel. The impression must be deep enough to prevent the identification(s) from being obscured by subsequent painting of the building and attached service equipment.

11. The Company may require the assistance of the Customer and/or the Customer's contractor to open the apartments or offices at the time the meters are set, in order to verify that each meter socket actually serves the apartment or office indicated by the marking tag. In the case of multiple buildings the building or unit number and street address will be identified on the pull section in the manner described above.

D. Grounds for Refusal of Service

The Company may refuse to establish service if any of the following conditions exist:

1. When the Applicant or affiliate of the Applicant with common ownership has an outstanding amount due for the same class of electric service with the Company and the Applicant is unwilling to make arrangements with the Company for payment, in such cases, the Company shall be entitled to transfer the balance due or credit owed on

the terminated service to any other active account of the Customer for the same class of service. The failure of the Customer to pay the active account shall result in the suspension or termination of service.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

2. A condition exists which, in the Company's judgment, is unsafe or hazardous to the Applicant, the general population, or the Company's personnel or facilities;

3. The Applicant refuses to provide the Company with a deposit when the Customer has failed to meet the credit criteria for waiver of deposit requirements;

4. Customer is known to be in violation of the Company's Rates or Rules and Regulations;

5. Customer fails to furnish the funds, service, equipment, and/or rights-of-way necessary to serve the Customer and which have been specified by the Company as a condition for providing service;

6. Customer fails to provide safe access to the meter that would be serving the Customer;

7. Applicant falsifies his or her identity for the purpose of obtaining service;

8. Service is requested by an Applicant and a prior Customer, who is either living with the Applicant, or who is an occupant of the premises who owes a debt to the Company from the same class of service from the same or a prior service address;

9. The Applicant is acting as an agent for a prior Customer who is deriving benefits from the energy supplied and who owes a delinquent bill from the same class of service from the same or a prior service address;

10. There is evidence of tampering or energy diversion.

~~10.~~11. Where the Company has a reasonable belief that the Applicant has common ownership with an affiliate that owes a delinquent bill for the same class of service.

E. Service Establishment, Reestablishment or Reconnection Charge

1. The Company will make a charge, as approved by the ACC, for service transfer for meter reads only set forth as Fee No. 1 in the UNS Electric Statement of Charges.

2. The Company may make a charge, as approved by the ACC, for the establishment, reestablishment, or reconnection of service. The charge for establishment, reestablishment or reconnection of service during regular business hours is set forth as Fee No. 4 in the UNS Electric Statement of Charges.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

3. Should service be established, reestablished or reconnected during a period other than the Company's regular business hours, at the Customer's request, the Customer may be required to pay an after-hour charge for the service connection set forth as Fee No. 5 in the UNS Electric Statement of Charges. Where the Company's scheduling will not permit service establishment, reestablishment or reconnection of service on the same day as requested, the Customer can elect to pay the after-hour charge for establishment that day, or ~~his~~ service will be established on the next available business day. ~~The after-hour charge is set forth as Fee No. 5 in the UNS Electric Statement of Charges.~~ Even so, a Customer's request to have the Company establish service after-hours is subject to the Company having Staff available; there is no guarantee that the Company will have the staffing available for service establishment, ~~or~~ reestablishment or reconnection of service outside of regular business hours.

4. For the purpose of this Rule, the definition of service establishment is where the Customer's facilities are ready and acceptable to the Company, the Applicant has obtained all required permits and/or inspections indicating that the Applicant's facilities comply with local construction safety and governmental standards and regulations, and the Company needs only to install a meter, read a meter, or turn the service on.

5. Service Reconnection Charge

   Whenever the Company has discontinued service under its usual operating procedures because of any default by the Customer as provided herein, a reconnection charge, not to exceed the charge for the reestablishment of service as set forth as Fee Nos. 4–5 in the UNS Electric Statement of Charges, shall be made and may be collected by the Company before service is restored. When, due to the behavior of the Customer, it has been necessary to discontinue service utilizing other than usual operating procedures, the Company shall be entitled to charge Fee No. 6 ~~and collect actual costs~~ to restore service, as set forth in the UNS Electric Statement of Charges.

F. Temporary Service

1. Applicants for temporary service may be required to pay Line Extension charges in accordance with Section 7.C.9.d.

2. Where the duration of service is to be less than one (1) month, the Applicant will also be required to advance a sum of money equal to the estimated bill for service.

3. Where the duration of service is to exceed one (1) month, the Applicant may also be required to meet the deposit requirements of the Company, as outlined in Subsection B.1. above.

4. If at any time during the term of the agreement for service the character of a temporary Customer's operations changes so that, in the opinion of the Company, the Customer is classified as permanent, the terms of the Company's Line Extension rules will apply.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

G. Identification of Load and Premises

Upon request of the Company, the electric load and premises to be served by the Company must be clearly identified by the Customer at the time of application. If the service address is not recognized in terms of commonly used identification system, the Customer may be required to provide specific written directions and/or legal descriptions before the Company will be required to act upon a request for electric service.

H. Identification of Responsible Party

Any person applying on behalf of another Customer for service to be connected in the name of or in care of another Customer must furnish to the Company written approval from that Customer guaranteeing payment of all bills under the account. The Customer is responsible in all cases for service supplied to the premises until the Company has received proper notice of the effective date of any change. The Customer shall also promptly notify the Company of any change in physical or electronic billing address.

I. Tampering With or Damaging Company Equipment

1. The Customer agrees, when accepting service, that no one except authorized Company employees or agents of the Company will be allowed to remove or replace any Company owned equipment installed on Customer's property.

2. No person, except an employee or agent acting on behalf of the Company shall alter, remove or make any connection to the Company's meter or service equipment.

3. No meter seal may be broken or removed by anyone other than an employee or agent acting on behalf of the Company; however, the Company may give its prior consent to break the seal by an approved electrician employed by a Customer when deemed necessary by the Company.

4. The Customer will be held responsible for any broken seals, tampering, or interfering with the Company's meter(s) or any other Company owned equipment installed on the Customer's premises. In cases of tampering with meter installations, interfering with the proper working thereof, or any tampering, interfering, theft, or service diversion, including the falsification of Customer read-meter readings, Customer will be subject to immediate discontinuance of service. The Company will be entitled to collect from the Customer ~~whose name the service is in~~or other person benefitting from the service, under the appropriate Rate, for all power and energy not recorded on the meter as the result of such tampering, or other theft of service, and also additional security deposits as well as all expenses incurred by the Company for property damages, investigation of the illegal act, and all legal expenses and court costs incurred by the Company.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

5. The Customer will be held liable for any loss or damage occasioned or caused by the Customer's negligence, want of proper care or wrongful act or omission on the part of any Customer's agents, employees, licensees or contractors.

J. Access

1. The Customer is responsible for providing safe access to Company facilities. The Company's authorized agents shall have satisfactory unassisted twenty-four (24) hour a day, seven (7) days a week access to the Company's equipment located on Customer's premise for the purpose of service connection, service disconnection, operation, maintenance, repair and service restoration work that the Company may need to perform.

2. If additional resources are required to gain safe access to perform service establishment, disconnection, meter reading, or routine maintenance, due to an affirmative, wrongful, and/or criminal act by the Customer, the Company will be entitled to collect from the Customer all expenses incurred by the Company for additional resources including: investigation of access, all legal expenses, and court costs.

K. Customer-Specific Information

Customer-specific information shall not be released without specific prior Customer authorization unless the information is requested by law enforcement or other public agency, or is requested by the Commission or its staff, or is reasonably required for legitimate account collection activities, or is necessary to provide safe and reliable service to the Customer. Such Customer authorization may be obtained electronically, in writing, or orally, as long as the oral authorization is recorded.

SECTION 4
MINIMUM CUSTOMER INFORMATION REQUIREMENTS

A. Information for Customers

1. The Company will make available upon Customer request not later than sixty (60) days from the date of the request a concise summary of the Rate schedule applied for by the Customer. The summary will include the following:

   a. The monthly minimum Customer charge, identifying the amount of the charge and the specific amount of usage included in the minimum charge, where applicable;

   b. Rate blocks, where applicable;

   c. Any adjustment factor(s) and method of calculation; and

   d. Demand charge, where applicable.

2. Upon request of the Customer, either at the time of application or after, the Company will use its best efforts to assist the Customer in choosing an appropriate Rate. However, upon application or upon request for assistance, the Applicant or the Customer will elect the applicable Rate best suited to his requirements. The Company may assist in making this election, but will not be held responsible for notifying the Customer of the most favorable Rate and will not be required to refund the difference in charges under different Rates. The Customer is solely responsible for selecting the Rate the Customer believes is appropriate. If no Rate is selected; the Customer will be placed on the most common Rate for the class of service and the Company will not be liable to refund the difference in charges had the Customer been placed on different Rates.

3. Upon written notification of any material changes in the Customer's installation or load conditions, the Company will assist in determining if a change in Rate is desirable, but not more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

4. The supply of electric service under a residential Rate to a dwelling involving some business or professional activity will be permitted only where this activity is only occurring occasionally at the dwelling, where the electricity used in connection with this activity is small in amount, and where the electricity is used only by equipment that would normally be in use if the space were used as living quarters. Where a portion of the dwelling is used regularly for business, professional and other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or for electrical equipment not normally used in living quarters is installed in connection with the activities referenced above, then the entire premises will be classified as non-residential and the appropriate general service Rate will be applied. The Customer, may, at his option, provide separate wiring so that the residential uses can be metered and billed separately under the appropriate residential service rate schedule, and the other uses under the appropriate general service rate.

SECTION 4
MINIMUM CUSTOMER INFORMATION REQUIREMENTS
(continued)

5. In addition, the Company will make available upon Customer request, not later than sixty (60) days from date of service commencement, a concise summary of the Company's Rates or the ACC's Rules and Regulations concerning:

    a. Deposits;

    b. Termination of service;

    c. Billing and collection; and

    d. Complaint handling.

6. The Company, upon request of a Customer, will transmit a written statement of actual consumption by the Customer for each billing period during the prior twelve (12) months, unless this data is not reasonably ascertainable. But the Company will not be required to accept more than one such request from each Customer in a calendar year. The Company may charge the Customer for consumption history requests as set forth as Fee No. 8 in UNS Electric Statement of Charges.

B. Information Required Due to Changes in Rates:

1. The Company will send to affected Customers a concise summary of any change in the Rates affecting those Customers.

2. This information will be sent to the affected Customer within sixty (60) days of the effective date of the change.

SECTION 5
MASTER METERING

A. Mobile Home Parks – New Construction/Expansion

1. The Company will refuse service to all new construction or expansion of existing permanent residential mobile home parks unless the construction or expansion is individually metered by the Company. Line extensions and service connections to serve this expansion will be governed by the Company's Line Extension and/or service connection policies of these Rules and Regulations.

2. Permanent residential mobile home parks for the purpose of this rule will mean mobile home parks where the average length of stay for an occupant is a minimum of six (6) months.

3. For the purposes of this rule, expansion means the acquisition of additional real property for permanent residential spaces in excess of that existing at the effective date of this rule.

B. Residential Apartment Complexes, Condominiums and other Multiunit Residential Buildings

1. Master metering will not be allowed for new construction of apartment complexes and condominiums unless the building or buildings will be served by a centralized heating, ventilation, or air conditioning system and the contractor can provide to the Company an analysis demonstrating that the central unit will result in a favorable cost/benefit relationship.

2. At a minimum, the cost/benefit analysis should consider the following elements for a central unit as compared to individual units:

   a. Equipment and labor costs;

   b. Financing costs;

   c. Maintenance costs;

   d. Estimated kWh usage;

   e. Estimated kW demand on a coincident demand and non-coincident demand basis (for individual units);

   f. Cost of meters and installation; and

   g. Customer accounting cost (one account vs. several accounts).

3. A Customer of any residential apartment complex, condominium, or other multiunit residential building taking service through a master meter is responsible for determining his or her own usage beyond the Company's meter.

SECTION 6
SERVICE LINES AND ESTABLISHMENTS

A. Priority and Timing of Service Establishments

1. After the Applicant has complied with the Company's application requirements and has been accepted for service by the Company, and obtained all required permits and/or inspections indicating that the Customer's facilities comply with local construction, safety and governmental standards or regulations, the Company will schedule that Customer for service establishment.

2. All charges are due and payable before the Company will schedule the Customer for service establishment.

3. Service establishments will be scheduled for completion within five (5) business days of the date the Customer has been accepted for service, except in those instances when the Customer requests service establishment beyond the five (5) business day limitation.

4. When the Company has made arrangements to meet with a Customer for service establishment purposes and the Company or the Customer cannot make the appointment during the prearranged time, the Company will reschedule the service establishment to the satisfaction of both parties.

5. The Company will schedule service establishment appointments within a maximum range of four (4) hours during normal business hours, unless another timeframe is mutually acceptable to both the Company and the Customer.

6. Service establishments will be made only by the Company.

B. For the purposes of the rule, service establishments are where the Customer's facilities are ready and acceptable to the Company and the Company needs only to install or read a meter or turn the service on.Service Lines

1. Customer provided facilities

a. Each Applicant for services will be responsible for all inside wiring including the service entrance and meter socket. For three-phase service, the Customer will provide, at the Customer's expense, all facilities including conductors and conduit, beyond the Company-designated point of delivery.

b. Meters and service switches in conjunction with the meter will be installed in a location where the meters will be readily and safely accessible for reading, testing and inspection, where these activities will cause the least interference and inconvenience to the Customer. Location of metering facilities will be determined by the Company and may or may not be at the same location as the point of delivery. However, the meter locations will not be on the front exterior wall of the home, or in the carport or garage unless mutually agreed to between the Customer or homebuilder and the Company. Without cost to the Company, the Customer must provide, at a suitable and easily accessible location, sufficient and proper space for the installation of meters.

~~7. A fee for service establishment, reestablishment, or reconnection of service may be charged at a rate on file with and approved by the ACC. Whenever an Applicant requests after-hours handling of his request, the Company will charge a fee set forth in the UNS Electric Statement of Charges, unless a special call-out is required. If a special~~

~~call-out is required the charge will be for a minimum of two (2) hours at the Company's then-prevailing after-hours rate for the service work on the Customer's premises. Special handling of calls and the related charges will be made only upon request of the Applicant. Even so, a Customer's request to have the Company establish service after-hours is subject to the Company having staff available; there is no guarantee that the Company will have the staffing available for service establishment, reestablishment or reconnection after regular business hours.~~

SECTION 6
SERVICE LINES AND ESTABLISHMENTS
(continued)

c. Where the meter or service line location on the Customer's premises is changed at the request of the Customer or due to alterations on the Customer's premises, the Customer must provide and have installed, at the Customer's expense, all wiring and equipment necessary for relocating the meter and service line connection. The Company will charge the Customer for moving the meter and/or service lines.

d. Customer will provide access to a main switch or breaker for disconnecting load to enable safe installation and removal of Company meters.

2. Company-Provided Facilities

a. The Company will provide, at no charge, an overhead service line up to ~~one~~five hundred fifty (~~1~~550) feet~~ and no more than one carryover pole, if required,~~ for each Customer. In areas where the Company maintains an underground distribution system, the Company will provide, install, and connect, at no charge, underground service cable up to ~~one~~five hundred fifty (~~1~~550) feet for each residential Customer.

b. The cost of any service line in excess of that allowed under 2.a. above will be paid for by the Customer as a contribution in aid of construction.

c. A Customer requesting an underground service line in an area served by overhead facilities will pay for the difference between estimated cost of an equivalent overhead service connection and the actual cost of the underground connection as a non-refundable contribution.

3. Overhead Service Connection – Secondary Service

a. For the initial service drop: Where the Company's distribution pole line is located on the Customer's premises, or on a street, highway, lane, alley, road, or private easement immediately contiguous thereto, the Company will, at its own expense, furnish and install a single span of service drop line (up to 550 feet in total) from its pole to the Customer's point of attachment, provided that this point of attachment is at the point of delivery and is of a type and so located that the service drop wires may be installed in a manner approved by the Company in accordance with good engineering practice, and in compliance with all applicable laws, ordinances, Rules and Regulations, including those governing clearances and points of attachment.

b. Whenever any of the clearances required by the applicable laws, ordinances, rules or regulations of public authorities or standards of the Company from the service drops to the ground or any object becomes impaired by reason of any changes made by the owner or tenant of the premises, the Customer will, at his own expense, provide a new and approved support, in a location approved by the Company, for the termination of the Company's service drop wires and will also provide all service entrance corridors and equipment necessitated by the change of location.

c. The cost of any service line footage, in excess of that allowed at no charge, will be paid for by the Customer as a contribution in aid of construction.

SECTION 6
SERVICE LINES AND ESTABLISHMENTS
(continued)

d. For each overhead service connection, the Customer will furnish at their own expense a set of service entrance conductors that will extend from the point of service delivery at the point of termination of the Company's service drop on the Customer's support to the Customer's main disconnect switch. These service entrance conductors will be of a type and be in an enclosure that meets with the approval of the Company and any inspection authorities having jurisdiction.

4. Underground Service Connections – Secondary Service

   a. In areas where the Company maintains an underground distribution system, individual services will be underground.

   b. The cost of any underground service line footage, in excess of that allowed at no charge, will be paid for by the Customer and will be treated as a contribution in aid of construction.

   c. Whenever the Company's underground distribution system is not complete to the point designated by the Company where the service lateral is to be connected to the distribution system, the system may be extended in accordance with Section 7.

   d. For an initial underground service connection of single-phase service, the Company will install a service lateral from its distribution line to the Customer's Company-approved termination facilities under the following conditions (unless otherwise agreed to by the Company and the Applicant):

      (i) The Customer, at his expense, will provide the necessary trenching, conduit, conduit installation, backfill, landscape restoration and paving and will also furnish, install, own and maintain termination facilities on or within the building to be served.

   e. The Company, at its expense (up to 550 feet in total), will furnish, install, own and maintain the underground single-phase cables to Customer's Company-approved termination facilities.

   f. The Company will determine the minimum size and type of conduit and conductor for the single-phase service. The Customer will furnish and install the conduit system, including suitable pull ropes as specified by the Company. The ownership of this conduit or duct will be conveyed to the Company, and the Company will thereafter maintain the conduit or duct. The maximum length of any lateral conductor will be determined by the Company in accordance with accepted engineering practice in determining voltage drop, voltage flicker, and other relevant considerations.

   g. For three-phase service, the Customer will provide, at the Customer's expense, all facilities, including conductors and conduit, beyond the Company-designated point of delivery.

SECTION 6
SERVICE LINES AND ESTABLISHMENTS
(continued)

C. Easements and Rights-of-Way

1. At no cost to the Company, each Customer will grant adequate easements and rights-of-way that are satisfactory to ensure proper service connection and any additional easements and rights-of-way as may be necessary for electric system reliability. Failure on the part of the Customer to grant adequate easement and right-of-way will be grounds for the Company to refuse service.

2. When the Company discovers that a Customer or the Customer's Agent is performing work, has constructed facilities or has allowed vegetation to grow adjacent to or within an easement or right-of-way and this work, construction, vegetation or facility poses a hazard or is in violation of federal, state or local laws, ordinances, statutes, Rules or Regulations, or significantly interferes with the Company's access to equipment, the Company will notify the Customer or the Customer's Agent and will take whatever actions are necessary to eliminate the hazard, obstruction or violation at the Customer's expense.

D. Number of Services to be Installed

Unless otherwise provided herein, or in a Rate or contract, the Company will not install more than one service, either overhead or underground, for any one building or group of buildings on a single premise. Separate services may be installed for separate buildings or group of buildings where necessary for the operating convenience of the Company, where provided for in the Rates, or where required by law or local ordinance.

E. Multiple Service Points

Unless otherwise expressly provided herein, or in a Rate or contract, any person, firm, corporation, agency or other organization or governmental body receiving service from the Company at more than one location or for more than one separately operated business will be considered as a separate Customer at each location and for each business. If several buildings are occupied and used by a Customer in the operation of a single business, then the Company, upon proper application, will furnish service for the entire group of buildings through one service connection at one point of delivery, provided all of these buildings are at one location on the same lot or tract, or on adjoining lots or tracts that form a contiguous site (not separated by any public streets) wholly owned, or controlled, and occupied by the Customer in the operation of this single business. Dwelling units will be served, metered and billed separately, except at the option of the Company.

F. Temporary Service

For service that is temporary in nature or for operations of a speculative character or questionable permanency the Customer will be charged the Company's estimated cost of installing and removing the service.

SECTION 6
SERVICE LINES AND ESTABLISHMENTS
(continued)

G. Customer-Owned Cable

When a residential Customer's privately owned underground service cable has failed, the Customer has two (2) options:

1. The Customer can have their cable repaired by a private electrical contractor which must comply with local governmental codes and ordinances; or

2. The Customer can bring their service entrance up to current Company standards. The Customer will be required to provide a service trench, conduit, conduit installation, backfill, landscape restoration and paving. The Company will furnish, install, own and maintain its underground single-phase cables to the Customer's Company-approved Point of Delivery.

SECTION 7
LINE EXTENSIONS

Introduction

The Company will construct, own, operate and maintain lines along public streets, roads and highways which the Company has the legal right to occupy, and on public lands and private property across which rights-of-way and easements satisfactory to the Company may be obtained without cost to or condemnation by the Company.

A request for electric service often requires the construction of new distribution lines of varying distances. The distances and cost vary widely depending upon Customer's location and load size. With such a wide variation in extension requirements, it is necessary to establish conditions under which the Company will extend its electric facilities.

All extensions are subject to the availability of adequate capacity, voltage and Company facilities at the beginning point of an extension, as determined by the Company.

A standard policy has been adopted to provide service to Customers whose requirements are deemed by the Company to be economical and ordinary in nature.

All extensions are made on the basis of economic feasibility. Footage and revenue basis are offered below for use in circumstances where feasibility is generally accepted because of the number of extensions made within these footage and dollar units.

In unusual circumstances, when the application of the provisions of this policy appear impractical, or in case Customer's requirements exceed 100 kW, the Company will make a special study of the conditions to determine the basis on which service may be rendered.

A. General Requirements

1. Upon request by an Applicant for a line extension, the Company will prepare without charge, a preliminary electric design and a rough estimate of the cost of installation, if any, to be paid by said Applicant.

2. Any Applicant for a line extension requesting the Company to prepare detailed plans, specifications, or cost estimates will be required to make a non-refundable deposit with the Company in an amount equal to the estimated cost of preparation. The Company will make available within ninety (90) days after receipt of the deposit referred to above, those plans, specifications, and cost estimates for the proposed line extension. Where the Applicant authorizes the Company to proceed with construction of the extension, the deposit will be credited to the cost of construction. If the extension is to include over-sizing of facilities to be done at the Customer's expense, appropriate details will be set forth in the plans, specifications and cost estimates. Developers providing the Company with approved plats will be provided with plans, specifications, or cost estimates within ninety (90) days after receipt of the deposit referred to above.

   The Company will provide a copy of the Line Extension policy prior to the Applicant's acceptance of the utility's extension agreement.

<u>SECTION 7</u>
LINE EXTENSIONS
(continued)

3. All line extension agreements requiring payment of an advance by the Applicant will be in writing and signed by each party.

4. The provisions of this rule apply only to those Applicants who, in the Company's judgment, will be permanent Customers of the Company. Applications for temporary service will be governed by the Company's Rules concerning temporary service applications. The Company reserves the right to delay the extension of facilities until the satisfactory completion of required site improvements, as determined by the Company, and an approved service entrance to accept electric service has been installed.

B. Minimum Written Agreement Requirements

1. Each line extension agreement must, at a minimum, include the following information:

   a. Name and address of Applicant(s);

   b. Proposed service address(es) or location(s);

   c. Description of requested service;

   d. Description and sketch of the requested line extension;

   e. A cost estimate to include ~~itemized~~ material costs, labor<u> costs, overhead costs</u>, and <u>any </u>other ~~itemized~~ costs as necessary<u>.</u>~~; Calculations of estimated line extension costs will include the following:~~

   ~~i. Material cost;~~

   ~~ii. Direct labor cost; and~~

   ~~iii. Overhead cost.~~

   ~~1) Overhead costs are represented by all the costs which are proper capital charges in connection with construction, other than direct material and labor costs including but not limited to; indirect labor, engineering, transportation, taxes (e.g. FICA, State & Federal Unemployment which are properly allocated to construction), insurance, stores expense, general office expenses allocated to costs of construction, power operated equipment, employee pension and benefits, vacations and holidays, and miscellaneous expenses properly chargeable to construction.~~

   f. Payment terms;

   g. A concise explanation of any refunding provisions, if applicable;

   h. The Company's estimated start date and completion date for construction of the line extension; and

   i. A summary of the results of the economic feasibility analysis performed by the Company to determine the amount of the advance required from the Applicant for the proposed line extension.

2. Each Applicant will be provided with a copy of the written line extension agreement.

SECTION 7
LINE EXTENSIONS
(continued)

C. Line Extension Requirements

1. Overhead Extensions to Individual Residential Applicants

a. Line Extension Allowance

Upon the Applicant's satisfactory completion of required site improvements, the Company will make single-phase extensions from its existing facilities of proper voltage and adequate capacity at the Company's expense up to five hundred fifty (550) feet. The distance of five hundred fifty (550) feet is to be measured by the shortest feasible route along public streets, roads, highways, or suitable easements from the existing facilities to the Applicant's nearest point of delivery and inclusive of the service drop and is for initial site improvements, as determined by the Company, only.

b. Extensions in Excess of Line Extension Allowance Distance

The Company will make extensions in excess of five hundred fifty (550) feet per Customer upon receipt of a non-interest bearing, refundable cash deposit with the Company to cover the estimated costs of construction for the pro-rata share of the single-phase extension length over five hundred fifty (550) feet, for voltages up to 21kV.

The Company will install, own and maintain, on an individual project basis, the distribution facilities necessary to provide permanent service.

c. Method of Refund

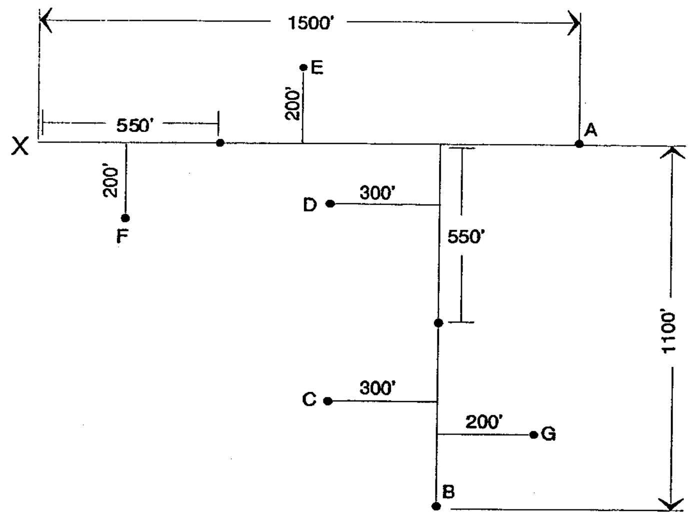
i. Deposit refunds will be made to a depositor when separately metered Customers are served directly from the line extension originally constructed to serve said depositor, providing the new line extension is less than five hundred fifty (550) feet in distance, and the Customer to be served occupies a permanent structure designed for continued occupancy for either residential or business purposes, meeting established municipal, county or state codes as applicable.

The amount of the deposit refund will be equal to the estimated 'Cost per Foot' for the line extension project rate multiplied by five hundred fifty (550) feet less the actual footage of the new line extension required to serve the new Customer.

In no event will the total of the refund payments made by the Company to a depositor be in excess of the deposit amount advanced.

SECTION 7
LINE EXTENSIONS
(continued)

A pictorial explanation of the method of refund for a single-phase line extension is as follows (assume the 'Cost per Foot' rate for this Line Extension is $15.00 per foot):



Applicant "A" – Customer makes refundable advance of $14,250 for footage over 550' at $15.00/foot.

Applicant "B" – Customer makes refundable advance of $8,250 for footage over 550' at $15.00/foot. No refund to A for B's connection because B is over 550'.

Applicant "C" – Customer gets line at no cost. Refund goes to B at $15.00 x 250', or $3,750 because C ties directly into B's line and is less than 550'.

Applicant "D" – Customer gets line at no cost. Refund goes to B at $15.00 x 250', or $3,750, because it ties directly into B's line and is less than 550'.

Applicant "E" – Customer gets line at no cost. Refund goes to A at $15.00 x 350', or $5,250 because E ties directly into A's line and is less than 550'.

Applicant "F" – Customer gets line at no cost. Refund goes to A at $15.00 x 350', or $5,250 because F ties directly into A's line and is less than 550'.

Applicant "G" – Customer gets line at no cost. Refund goes to B at $15.00 x 350', or $5,250; however, B receives $750 since this is the remaining balance of the initial deposit net of refunds. Total refunds cannot exceed the amount of the initial advance.

SECTION 7
LINE EXTENSIONS
(continued)

Note: The dollars in the example above are illustrative. This method requires that: a) The deposit advance made for an initial line extension cannot be refunded to the depositor unless a new line extension required to serve a new separately metered Customer is directly connected to the initial line extension; and b) the new line extension is less than 550 feet in length.

ii. Payment of eligible refunds will be made within ninety (90) days following receipt of notification to the Company that a qualifying permanent Customer has commenced receiving service from an extension.

iii. A Customer may request an annual survey to determine if additional Customers have been connected to and are using service from the extension.

iv. After a period of five (5) years from the date the Company is initially ready to render service from an extension, the Company will review the deposit and make appropriate refunds then due, if any. Any unrefunded amount remaining thereafter will become the property of the Company and will no longer be eligible for refund and will become a contribution in aid of construction.

2. Underground Facilities to Individual Residential Applicants

a. Underground line extensions will generally be made only where mutually agreed upon by the Company and the Applicant, or in areas where the Company does maintain underground distribution facilities for its operating convenience.

b. Underground extensions will be owned, operated and maintained by the Company, provided the Applicant pays in advance a non-refundable sum equal to the estimated difference between the cost, exclusive of meters and services, of the underground extension and an estimated equivalent overhead extension cost for voltages up to 21kV.

c. In addition to the non-refundable sum, the Applicant will (unless otherwise agreed to by the Company and the Applicant) make such refundable deposit (for voltages up to 21kV) in accordance with Subsection 7.C. as otherwise would have been required under these Rules and Regulations if the extension had been made by overhead construction.

d. Refunds of cash deposits will be made in the same manner as provided for overhead extensions to individual Applicants for service, in accordance with the applicable provisions of Subsection 7.C.

e. Underground services will be installed, owned, operated and maintained as provided in Section 6 of these Rules and Regulations.

SECTION 7
LINE EXTENSIONS
(continued)

3. Extensions to Non-Residential Customers

a. Line Extensions less than 21kV

i. For line extensions with voltages less than or equal to 21kV, the Company will install, own and maintain, on an individual project basis, the distribution facilities necessary to provide permanent service to a non-residential Customer. Prior to the installation of facilities, the Customer will be required to make a refundable non-interest-bearing cash advance to the Company for the estimated project cost less an allowance equal to 50% of the estimated two year Revenue. If the total of such charge is less than one hundred dollars ($100.00), the charge will be waived by the Company.

ii. Upon completion of construction of the Company's facilities the total actual cost of the project will be compared to the total estimated cost advanced by the Applicant, and any difference will be either billed or refunded within ninety (90) days to the Customer.

iii. After the initial twenty-four (24) month billing period the Company will compare the actual Revenue to the allowance, and any difference will be either billed or refunded within ninety (90) days to the Customer.

iv. In no event shall the total of the refund payments made by the Company to the depositor be in excess of the deposit amount advanced.

v. No refunds will be made after a period of two (2) years subsequent to the completion of construction of the Company's facilities. Any un-refunded amount remaining at the end of the two (2) year period will become the property of the Company and a nonrefundable contribution in aid of construction.

vi. 550 foot line extension allowance does not apply.

b. Line Extensions greater than 21kV to 69kV

i. For line extensions with voltages greater than 21kV and less than or equal to 69kV, the Company will install, own and maintain, on an individual project basis, the distribution facilities necessary to provide permanent service to a non-residential Customer. Prior to the installation of facilities, the Customer will be required to make a refundable non-interest-bearing cash advance to the Company for the estimated project cost less an allowance equal to 50% of the estimated one year Revenue. If the total of such charge is less than one hundred dollars ($100.00), the charge will be waived by the Company.

ii. Upon completion of construction of the Company's facilities the total actual cost of the project will be compared to the total estimated cost advanced by the Applicant, and any difference will be either billed or refunded within ninety (90) days to the Customer.

iii. After the initial twelve (12) month billing period the Company will compare the actual Revenue to the allowance, and any difference will be either billed or refunded within ninety (90) days to the Customer.

SECTION 7
LINE EXTENSIONS
(continued)

iv. In no event shall the total of the refund payments made by the Company to the depositor be in excess of the deposit amount advanced.

v. No refunds will be made after a period of two (2) years subsequent to the completion of construction of the Company's facilities. Any un-refunded amount remaining at the end of the two (2) year period will become the property of the Company and a nonrefundable contribution in aid of construction.

vi. 550 foot line extension allowance does not apply.

4. Residential Subdivision Developers

a. General

Required distribution facilities up to and within a new duly recorded residential subdivision, including subdivision plats which are activated subsequent to their recordation, for permanent service to single and/or multi-family residences and/or unmetered area lighting, will be constructed, owned, operated and maintained by the Company in advance of applications for service by permanent Customers only after the Company and the Applicant have entered into a written contract ("Subdivision Agreement"), which (unless otherwise agreed to by the Company and the Applicant) provides that:

i. The total estimated installed cost of such overhead distribution facilities, exclusive of meters, services and exclusive of other costs as may be deemed as reasonable by the Company, will be advanced to the Company as a refundable non-interest bearing cash deposit to cover the Company's cost of construction.

ii. Refundable advances will become non-refundable at such time and in such manner as provided in Subsection 7.C.4.b.

iii. Upon completion of construction of the Company's facilities the total actual cost of the project will be compared to the total estimated cost advanced by the Applicant, and any difference will be either billed or refunded within ninety (90) days to the Customer.

iv. Where applicable, if distribution facilities must be constructed in excess of an average of five hundred fifty (550) feet per new permanent Customer within a duly recorded residential subdivision, a nonrefundable cash amount equal to that portion of the total estimated installed cost represented by those required line facilities in excess of five hundred fifty (550) feet per Customer average will be paid to the Company.

SECTION 7
LINE EXTENSIONS
(continued)

v. Underground Installations – Extensions of single-phase underground distribution lines necessary to furnish permanent electric service to new residential buildings or mobile homes within a subdivision, in which facilities for electric service have not been constructed, for which applications are made by a developer will be installed underground in accordance with the provisions set forth in this regulation except where it is not feasible from an engineering, operational, or economic standpoint. Extensions of single-phase underground distribution lines necessary to furnish permanent electric service within a new single family and/or multi-family residential subdivision will be made by the Company in advance of receipt of applications for service by permanent Customers in accordance with the following provisions (unless otherwise agreed to by the Company and the Applicant):

1) The subdivider or other Applicant will provide the trenching, bedding, conduit, backfill (including any imported backfill required), compaction, repaving and any earthwork for pull boxes and equipment and transformer pad sites required in accordance with the Company's specifications and subject to the Company's inspection and approval.

2) Right-of-way and easements satisfactory to the Company will be furnished by the Developer at no cost to the Company and in reasonable time to meet service requirements. No underground electric facilities will be installed by the Company until the final grades have been established and furnished to the Company. In addition the easements, alleys and/or streets must be graded to within six (6) inches of final grade by the Developer before the Company will commence construction. Such clearance and grading must be maintained by the Developer. If, subsequent to construction, the clearance or grade is changed in such a way as to require relocation of underground facilities or results in damage to such facilities, the cost of such relocation and/or resulting repairs will be borne by the developer.

3) If armored cable or special cable covering is required, the Customer or developer will make a non-refundable contribution equal to the additional cost of such cable or covering.

4) Underground service lines will be installed, owned, operated and maintained as provided in Section 6 of these Rules and Regulations.

5) Any underground electric distribution system requiring more than single-phase service is not governed by this Subsection, but rather will be constructed pursuant to Subsection 7.C.7.

vi. Underground extensions up to the duly recorded Subdivision will be owned, operated and maintained by the Company, provided the Applicant pays a non-refundable sum equal to the estimated difference between the cost of the underground extension and an equivalent estimated cost of an overhead extension.

SECTION 7
LINE EXTENSIONS
(continued)

b. Method of Refund

i. The Developer is eligible for a refund during the term of the Subdivision Agreement of up to 100% of the amount advanced provided the average length of the line extension per lot or per service location does not exceed five hundred fifty (550) feet. If distribution facilities must be constructed in excess of an average of five hundred fifty (550) feet per new permanent lot or service location within a duly recorded residential subdivision, that portion of the advanced total installed cost represented by those required line facilities in excess of five hundred fifty (550) feet per customer will be held by the Company as a non-refundable contribution.

ii. On or after one (1) year subsequent to the installation of the Company's facilities, and thereafter each year of the term of the Subdivision Agreement the Company will review the status of the subdivision to determine the percentage ratio that the number of lots or service locations occupied by permanent Customers bears to the number of lots identified in each Subdivision Agreement specified as the basis for refund. The ratio determined at the time of each review multiplied by the total refundable advance associated with the line extension agreement will represent that portion of the advance qualified for refund. If the foregoing calculation indicates a refund is due, an appropriate refund of cash deposit will be made. Payment will be made within ninety (90) days following each review.

iii. The total amount refunded over the term of the Subdivision Agreement cannot exceed the total amount advanced net of any non-refundable contribution and or cost of ownership.

iv. The Company will make a final review on the status after a period of five (5) years. No refunds will be made after a period of five (5) years subsequent to the completion of construction of the Company's facilities. Any unrefunded amount remaining at the ends of the five (5) year period will become the property of the Company and a nonrefundable contribution in aid of construction.

5. Non-Residential Developers

a. General

Required distribution facilities up to and within a new duly recorded non-residential development, including commercial plats which are activated subsequent to their recordation, for permanent service, will be constructed, owned, operated and maintained by the Company in advance of applications for service by permanent commercial customers only after the Company and the Applicant have entered into a written contract which (unless otherwise agreed to by the Company and the Applicant) provides that:

i. For line extensions with voltages less than or equal to 21kV, the Company will install, own and maintain, on an individual project basis, the distribution facilities necessary to provide permanent service to a non-residential Customer. Prior to the installation of facilities, the Customer will be required to make a refundable non-interest-bearing cash advance to the Company for the estimated project cost less an allowance equal to 50% of the estimated two year Revenue. If the total of such charge is less than one hundred dollars ($100.00), the charge will be waived by the Company.

SECTION 7
LINE EXTENSIONS
(continued)

ii. Upon completion of construction of the Company's facilities the total actual cost of the project will be compared to the total estimated cost advanced by the Applicant, and any difference will be either billed or refunded within ninety (90) days to the Customer.

iii. Five-hundred fifty (550) foot line extension allowance does not apply.

iv. For line extensions with voltages greater than 21kV Subsection 7.C.3.b will apply.

b. Method of Refund

i. After the initial twenty-four (24) month billing period the Company will compare the actual Revenue to the allowance, and any difference will be either billed or refunded within ninety (90) days to the Customer.

ii. In no event shall the total of the refund payments made by the Company to the depositor be in excess of the deposit amount advanced.

iii. No refunds will be made after a period of two (2) years subsequent to the completion of construction of the Company's facilities. Any unrefunded amount remaining at the end of the two (2) year period will become the property of the Company and a nonrefundable contribution in aid of construction.

c. Underground Installations – Extensions of single-phase or three-phase underground distribution lines necessary to furnish permanent electric service to new commercial properties a commercial subdivision, in which facilities for electric service have not been constructed, for which applications are made by a developer will be installed underground in accordance with the provisions set forth in this regulation except where it is not feasible from an engineering, operational, or economic standpoint. Extensions of single-phase or three-phase underground distribution lines necessary to furnish permanent electric service will be made by the Company in advance of receipt of applications for service by permanent commercial customers in accordance with the following provisions (unless otherwise agreed to by the Company and the Applicant):

i. The subdivider or other Applicant will provide the trenching, bedding, backfill (including any imported backfill required), compaction, repaving and any earthwork for pull boxes and equipment and transformer pad sites required in accordance with the Company's specifications and subject to the Company's inspection and approval.

ii. Underground service will be installed, owned, operated and maintained as provided in Section 6 of these Rules and Regulations.

iii. Underground extensions up to the duly recorded Subdivision will be owned, operated and maintained by the Company, provided the Applicant pays a non-refundable sum equal to the estimated difference between the cost of the underground extension and an equivalent estimated cost of an overhead extension.

SECTION 7
LINE EXTENSIONS
(continued)

6. Replacement of Overhead with Underground Distribution Facilities

Where a Customer has requested that existing overhead distribution facilities be replaced with underground distribution facilities, the total cost of such replacement will be paid by the Customer.

7. Conversion from Single-Phase to Three-Phase Service

Where it is necessary to convert all or any portion of an existing overhead or underground distribution system from single-phase to three-phase service to a Customer, the total cost of such conversion will be paid by the Customer.

8. Long Term Rental Mobile Home Park, Townhouses, Condominiums and Apartment Complexes

Line extensions to long term rental mobile home parks, townhouses, condominiums and apartment complexes will be made by the Company under terms and conditions provided in Subsection 7.C.1. The Company will, when requested by the Customer, install, own and maintain internal distribution facilities and individual metering for said development in accordance with the provisions pertaining to duly recorded real estate subdivisions as stated in Subsection 7.C.2 hereof.

9. Special Conditions

a. Contracts

Each sub divider or other Applicant for service requesting an extension over the allowable footage allowance, or in advance of applications for service to permanent Customers, or in advance of completion of required site improvements will (unless otherwise agreed to by the Company and the Applicant) be required to execute contracts covering the terms under which the Company will install lines at its own expense, or contracts covering line extensions for which advance deposits will (unless otherwise agreed to by the Company and the Applicant) be made in accordance with the provisions of these Rules and Regulations or of the applicable rate schedules.

b. Primary Service and Metering

The Company will provide primary service to a point of delivery, such point of delivery to be determined by the Company. The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The system will be treated as primary service for the purposes of billing. The Company reserves the right to approve or require modification to the Customer's distribution system prior to installation, and the Company will determine the voltage available for primary service. Instrument transformers, metering riser poles and associated equipment to be installed and maintained by the Company will be at the Customer's expense.

SECTION 7
LINE EXTENSIONS
(continued)

c. Advances under Previous Rules and Contracts

Amounts advanced under the conditions established by a rule previously in effect will be refunded in accordance with the requirements of such contract under which the advance was made.

d. Extensions for Temporary Service

Extensions for temporary service or for operations of a speculative character (mining, milling, irrigation and similar speculative businesses) or questionable permanency will be charged the applicable estimated charges for the installation and removal of temporary facilities. Temporary facilities will remain in service for a maximum of two (2) years.

e. Exceptional Cases

Where unusual terrain, location, soil conditions, or other unusual circumstances make the application of these line extension rules impractical or unjust to either party or in the case of extension of lines of other than standard distribution voltage, service under such circumstances will be negotiated under special agreements specifying terms and conditions covering such extensions.

f. Special or Excess Facilities

Under this rule, the Company will install only those facilities which it deems are necessary to render service in accordance with the rate schedules. Where the Customer requests facilities which are in addition to, or in substitution for, the standard facilities which the Company normally would install, the extra cost thereof will be paid by the Customer.

g. Unusual Loads

Line extensions to unusually small loads not serving a permanent structure designed for continued occupancy for either residential or business purposes~~not consisting of a residence or permanent building~~ (e.g. individual lights, wells, signs, etc.) will not be granted the five hundred fifty (550) foot allowance, but will instead be required to advance any costs of service.

10. Other Conditions

a. Rights-of-Way – All necessary easements or rights-of-way required by the Company for any portion of the extension which is either on premises owned, leased or otherwise controlled by the Customer, Developer, or others will be furnished in the Company's name by the Customer without cost to or condemnation by the Company and in reasonable time to meet proposed service requirements. All easements or rights-of-way obtained on behalf of the Company will contain only those terms and conditions that are acceptable to the Company.

SECTION 7
LINE EXTENSIONS
(continued)

b. Change of Grade – If subsequent to construction of electric distribution and/or transmission lines and services, the final grade established by the Customer or Developer is changed in such a way as to require relocation of the Company facilities or results in damage to those same facilities, the cost of relocation and/or resulting repairs will be borne by the Customer or Developer.

c. Relocation – When the Company is requested to relocate its facilities for the benefit and/or convenience of a Customer, the Customer will pay the Company for the total cost of the work to be performed prior to the start of construction.

d. Connecting or Disconnecting Customer's Service – Only duly authorized employees of the Company are allowed to connect the Customer's service to, or disconnect the same from, the Company's electric lines.

e. Maintenance of Customer's Equipment – The Customer will, at the Customer's own risk and expense, furnish, install and keep in good and safe condition all electrical wires, lines, machinery and apparatus which may be required for receiving electric energy from the Company, and for applying and utilizing that energy, including all necessary protective appliances and suitable building therefore, and the Company will not be responsible for any loss or damage occasioned or caused by the negligence, want of proper care, or wrongful act of the Customer or any of the Customer's agents, employees or licensees on the part of the Customer in installing, maintaining, using, operating or interfering with any such wires, lines, machinery or apparatus.

f. Removal of Company Property – As provided for in these Rules and Regulations, the Company will have the right to remove any and all of its property installed on the Customer's premises at the termination of service.

g. Change of Customer's Requirements – In the event that the Customer must make any material change either in the amount or character of the appliances or apparatus installed upon the Customer's premises to be supplied with electric energy by the Company, the Customer must immediately give the Company written notice to this effect.

h. Refunds – In no case will the total of any refund payments made by the Company exceed the amount of any construction advance

i. Collections – Nothing in these Rules and Regulations will be construed as limiting or in any way affecting the right of the Company to collect from the Customer any other additional sum of money which may become due and payable.

SECTION 7
LINE EXTENSIONS
(continued)

D. Construction / Facilities Related Income Taxes

1. Collection of Income Tax Gross Up

a. Any federal, state or local income taxes resulting from the receipt of a Contribution or Advance in Aid of Construction in compliance with this rule is the responsibility of the Company and will be recorded as a deferred tax asset and reflected in the Company's rate base for ratemaking purposes.

b. However, if the estimated contribution or advance for any service line or distribution main extension (as determined for each individual extension agreement) exceeds $500,000, the Company shall require the Applicant to include in the contribution or advance an amount (the "gross up amount") equal to the estimated federal, state or local income tax liability of the Company resulting from the contribution or advance computed as follows:

$$\text{Gross Up Amount} = \frac{\text{Advance or Contribution}}{(1 - \text{Statutory combined income tax rate})} - \text{Advance or Contribution}$$

c. After the Company's tax returns for the year of receipt of the advance or contribution are completed, if the statutory combined income tax rate is less than the rate used to calculate the gross-up, the Company shall refund to the Applicant an amount equal to such excess.

d. When a gross-up amount is to be collected in connection with an extension agreement, the contract will state the tax rate used to compute the gross up amount, and will also disclose the gross-up amount separately from the estimated cost of facilities.

2. Refund of Tax Gross Up

a. In the case of construction advance refunds made pursuant to Subsection 7.C.3 a pro rata portion of the gross up will be refunded when the amount of the underlying advance~~contribution~~ is refunded. Any remaining gross-up will be refunded on November 1 of each year as tax depreciation deductions are taken on the Company's tax returns. At the end of five (5) years from installation, the remaining gross up will be refunded at an amount that reflects the net present value of the Company's remaining tax depreciation deductions on the underlying advance discounted at the Company's authorized rate of return.

b. In the case of all other advances or deferred construction deposit agreements, the gross up will be refunded, or the amount of required deferred construction deposit will be reduced, as follows:

i. If the full amount of the advance is refunded prior to September 30th of the year following the year in which the advance is received, the entire amount of the gross-up will be refunded.

SECTION 7
LINE EXTENSIONS
(continued)

ii. For any amount of the advance not refunded as of September 30th of the year following the year in which the advance is received, on November 1st of each year a portion of the gross-up will be refunded based on the amount of the tax depreciation deductions taken by the Company on its federal and state income tax returns.

iii. When any advance is refunded after depreciation refunds pursuant to clause ii have begun, a pro rata portion of the gross up will be refunded reduced by the amount of depreciation refunds previously made for that portion of the gross up.

iv. For any advance that is not refunded at the end of the contract period, the remaining gross up will be refunded at an amount that reflects the net present value of the Company's remaining tax depreciation deductions on the underlying advance discounted at the Company's authorized rate of return.

3. Non-refundable Income Tax Gross Up for Contribution in Aid of Construction

a. At the option of the Customer, a non-refundable gross-up may be calculated as follows:

$$\text{Non-refundable Gross Up Amount} = \frac{(\text{Contribution Amount} - \text{Net Present Value of Tax Depreciation})}{(1 - \text{Current Tax Rate})} - \text{Contribution Amount}$$

4. Alternate Income Tax Gross Up for Advances in Aid of Construction

a. At the option of the Customer, a gross-up may be calculated as in Section 7.D.3.a when an advance is received. When the Customer has received its final advance refund the alternate gross-up will be recomputed as follows:

$$\text{Alternate Gross Up Amount} = \frac{(\text{Advance Amount} - \text{Net Present Value of (Advance Refunds + Tax Depreciation on Advances Not Refunded)}}{(1 - \text{Current Tax Rate})} - \text{Advance Amount}$$

SECTION 8
PROVISION OF SERVICE

A. Company Responsibility

1. The Company will be responsible for the safe transmission and distribution of electricity until it passes the point of delivery to the Customer.

2. The Company will be responsible for maintaining in safe operating condition all meters, equipment and fixtures installed on the Customer's premises by the Company for the purpose of delivering electric service to the Customer. However, the Company will not be responsible for the condition of meters, equipment, and fixtures damaged or altered by the Customer.

3. The Company may, at its option, refuse service until the Customer has obtained all required permits and/or inspections indicating that the Customer's facilities comply with local construction and safety standards, including any applicable Company specifications.

4. The Company will determine, in its sole discretion, the type of service (including voltage and Point of Delivery) to be furnished for utilization by the Customer. This includes determinations involving: 1) requirements to take Primary Service and Metering; and 2) service voltage (including for any new on-site generation installations or generation retrofits at the Customer's premises).

B. Customer Responsibility

1. Each Customer will be responsible for maintaining in safe operating condition all Customer facilities on the Customer's side of the point of delivery.

2. Each Customer will be responsible for safeguarding all Company property installed in or on the Customer's premises for the purpose of supplying electric service to that Customer.

3. Each Customer will exercise all reasonable care to prevent loss or damage to Company property, excluding ordinary wear and tear. The Customer will be responsible for loss of or damage to Company property on the Customer's premises arising from neglect, carelessness, misuse, diversion, or tampering and will reimburse the Company for the cost of necessary repairs or replacements.

4. Each Customer~~, regardless of who owns the meter,~~ will be responsible for payment for any equipment damage and/or estimated unmetered usage and all reasonable costs resulting from unauthorized breaking of seals, interfering, tampering or bypassing the Company meter.

5. Each Customer will be responsible for notifying the Company of any equipment failure identified in the Company's equipment.

SECTION 8
PROVISION OF SERVICE
(continued)

6. Each Customer will be responsible for informing the Company of, and meeting the Company's requirements regarding on-site or distributed generation (including distributed renewable resources and combined heat and power facilities) that the Customer or the Customer's agent intends to interconnect to the Company's transmission or distribution system. This includes compliance with all requirements contained within the Company's most current Interconnection Requirements for Distributed Generation, and the terms and conditions of the Company's Agreement for the Interconnection of Customer's Facility. Customer must also agree to enter into the Interconnection Agreement with the Company. Further, any interconnection must be in accordance with any applicable Commission regulation and order governing interconnection, as well as applicable laws.

7. The Customer, at his expense, may install, maintain and operate check-measuring equipment as desired and of a type approved by the Company, provided that this equipment will be installed so as not to interfere with operation of the Company's equipment. This is also provided that no electric energy will be remetered or submetered for resale to another or to others, except where such remetering will be done in accordance with the applicable orders of the Commission.

C. Continuity of Service

The Company will make reasonable efforts to supply a satisfactory and continuous level of service. However, the Company will not be responsible for any damage or claim of damage attributable to any interruption or discontinuation of service resulting from:

1. Any cause against which the Company could not have reasonably foreseen, or made provision for (*i.e* force majeure, see Subsection 8.E.);

2. Intentional service interruptions to make repairs or perform routine maintenance; or

3. Curtailment, including brownouts or blackouts.

D. Service Interruptions

1. The Company will make reasonable efforts to reestablish service within the shortest possible time when service interruptions occur.

2. In the event of a national emergency or local disaster resulting in disruption of normal service, the Company may, in the public interest, interrupt service to other Customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

SECTION 8
PROVISION OF SERVICE
(continued)

3. When the Company plans to interrupt service for more than four (4) hours to perform necessary repairs or maintenance, the Company will attempt to inform affected Customers at least twenty-four (24) hours in advance of the scheduled date and these repairs will be completed in the shortest possible time to minimize the inconvenience to the Customers of the Company.

4. The Commission will be notified of interruption in service affecting the entire system or any significant portion thereof. The interruption of service and cause will be reported by telephone to the Commission within four (4) hours after the responsible Company representative becomes aware of said interruption. A written report to the Commission will follow.

E. Interruption of Service and Force Majeure

1. The Company will make reasonable provision to supply a satisfactory and continuous electric service, but does not guarantee a constant or uninterrupted supply of electricity. The Company will not be liable for any damage or claim of damage attributable to any temporary, partial or complete interruption or discontinuance of electric service attributable to a force majeure condition as set forth in Subsections 8.E.4. and 8.E.5. or to any other cause which the Company could not have reasonably foreseen and made provision against, or which, in the Company's judgment, is necessary to permit repairs or changes to be made in the Company's electric generating, transmission, or distribution equipment, or to eliminate the possibility of damage to the Company's property or to the person or property of others.

2. Whenever the Company deems a condition exists that warrants interruption or limitation in the service being rendered, this limitation or interruption will not constitute a breach of contract and will not render the Company liable for damages suffered thereby or excuse the Customer from further fulfillment of the contract.

3. The use of electric energy upon the Customer's premises is at the risk of the Customer. The Company's liability will cease at the point where its facilities are connected to the Customer's wiring.

4. Neither the Company nor the Customer will be liable to the other for any act, omission, or circumstances (including, but not limited to, the Company's inability to provide electric service) occasioned by or in consequence of the following:

   a. flood, rain, wind, storm, lightning, earthquake, fire, landslide, washout or other acts of the elements;

   b. accident or explosion;

   c. war, rebellion, civil disturbance, mobs, riot, blockade or other act of the public enemy;

   d. acts of God;

   e. interference of civil and/or military authorities;

SECTION 8
PROVISION OF SERVICE
(continued)

f. strikes, lockouts, or other labor difficulties;

g. vandalism, sabotage, or malicious mischief;

h. usurpation of power, or the laws, rules, regulations, or orders made or adopted by any regulatory or other governmental agency or body (federal, state or local) having jurisdiction of any of the business or affairs of the Company or the Customer, direct or indirect;

i. breakage or accidents to equipment or facilities;

j. lack, limitation or loss of electrical or fuel supply; or

k. any other casualty or cause beyond the reasonable control of the Company or the Customer, whether or not specifically provided herein and without limitation to the types enumerated, and which by exercise of due diligence the Company or the Customer is unable to overcome.

5. A failure to settle or prevent any strike or other controversy with employees or with anyone purporting or seeking to represent employees will not be considered to be a matter within the control of the Company.

6. Nothing contained in this Section will excuse the Customer from the obligation of paying for electricity delivered or services rendered.

F. General Liability

1. Company will not be responsible for any third-party claims against Company that arise from Customer's use of Company's electric services, unless such claims are caused by the Company's willful misconduct or gross negligence.

2. Customer will indemnify, defend and hold harmless the Company (including the costs of reasonable attorney's fees) against all claims (including, without limitation, claims for damages to any business or property, or injury to, or death of, any person) arising out of any wrongful or negligent acts or omissions of the Customer, or the Customer's agents, in connection with the Company's service or facilities.

3. The liability of the Company for damages of any nature arising from errors, mistakes, omissions, interruptions, or delays of the Company, its agents, servants, or employees, in the course of establishing, furnishing, rearranging, moving, terminating, or changing the service or facilities or equipment shall not exceed an amount equal to the charges applicable under the Company's Rates (calculated on a proportionate basis where appropriate) to the period during which the error, mistake, omission, interruption or delay occurs, except if such damages are caused by the Company's willful misconduct or gross negligence.

SECTION 8
PROVISION OF SERVICE
(continued)

4. In no event will the Company be liable for any incidental, indirect, special, or consequential damages (including lost revenue or profits) of any kind whatsoever regardless of the cause or foreseeability thereof.

5. The Company will not be responsible in an occasion for any loss or damage caused by the negligence or wrongful act of the Customer or any of his agents, employees or licensees in installing, maintaining, using, operating or interfering with any electric facilities.

G. Construction Standards and Safety

The Company will construct all facilities in accordance with the provisions of the ANSI C2 Standards (National Electric Safety Code, 2007 edition, and other amended editions as are adopted by the ACC), the 2007 ANSI B31.1 Standards, the ASME Boiler and Pressure Vessel Code, and other applicable American National Standards Institute Codes and Standards, except for those changes the ACC makes or permits from time to time. In the case of conflict between codes and standards, the more rigid code or standard will apply.

SECTION 9
CHARACTER OF SERVICE – VOLTAGE, FREQUENCY AND PHASE

A. For Residential, Lighting and Miscellaneous Service – Energy supplied will be sixty (60) Hertz, single phase, alternating current, three-wire service, 120/240 volts for new service applications. The Company will provide 120 volts, two-wire for those Customers currently receiving that service.

B. Commercial and Industrial Service – Electric energy furnished under these Rules and Regulations will be sixty (60) Hertz alternating current energy, single or three (3) phase at the standard nominal voltages specified by the Company.

C. All electric energy supplied will be in accordance with ANSI voltage ratings for electric power systems and equipment.

D. All voltages referred to above are nominal voltages and may vary somewhat due to local conditions. The Company does not guarantee the constancy of its voltage or frequency, nor does it guarantee against its loss of one or more phases in a three-phase service. The Company will not be responsible for any damage to the Customer's equipment caused by any or all of these occurrences brought about by circumstances beyond its control.

E. Motor Protection

The following protective apparatus, to be provided by the Customer, is required on all motor installations:

1. No Voltage Protection: Motors that cannot be safely subjected to full voltage at starting must be provided with a device to insure that upon failure of voltage, the motors will be disconnected from the line. Said device should be provided with a suitable time delay relay;

2. Overload Protection: All motors whose voltage does not exceed 750 volts are to be provided with approved fuses of proper rating. Where the voltage exceeds 750 volts, protective devices are to be provided. In these cases it will be found desirable to install standard switching equipment. The installation of overload relays and no-voltage releases is recommended on all motors, not only as additional protection, but as a means of reducing the cost of refusing; and

3. Phase Reversal: Reverse phase relays and circuit breakers or equivalent devices are recommended on all polyphase installations to protect the installation in case of phase reversal or loss of one phase.

SECTION 9
CHARACTER OF SERVICE – VOLTAGE, FREQUENCY AND PHASE
(continued)

F. Load Fluctuation ~~a~~And Balance

1. Interference with Service: The Company reserves the right to refuse to supply loads of a character that may seriously impair service to any other Customers. In the case of hoist or elevator motors, welding machines, furnaces and other installations of like character where the use of electricity is intermittent or subject to violent fluctuations, the Company may require the Customer to provide at the Customer's own expense suitable equipment to reasonably limit those fluctuations.

2. The Company has the right to discontinue electric service to any Customer who continues to use appliances or other devices, equipment and ~~apparati~~apparatus detrimental to the service after the Company notifies the Customer of his or her causing detriment to the service.

3. Allowable Instantaneous Starting Current Values: The instantaneous starting current (determined by tests or based on limits guaranteed by manufacturers) drawn from the line by any motor must not exceed a value (as determined by the Company) that may be deemed detrimental to the normal operation of the system. If the starting current of the motor exceeds that value, a starter must be used or other means employed to limit the current to the value specified. A reduced voltage starter may be required for polyphase motors.

4. When three-phase service supplied under a power rate includes incidental lighting, the Customer will supply any necessary lighting transformers and arrange its lighting to give a substantially balanced three-phase load.

G. Customer Responsibility for Equipment Used in Receiving Electric Energy

No statement or requirement in these Rules and Regulations can be construed as the assumption of any liability by the Company for any wiring of electrical equipment or the operation of same, installed in, upon, or about the Customer's premises, nor will the Company be responsible for any loss or damage occasioned or caused by the negligence, want of proper care or wrongful act of the Customer, or any of the Customer's agents or employees or licenses on the part of the Customer in installing, maintaining, using, operating, or interfering with any such wiring, machinery or apparatus.

SECTION 10
METER READING

A. Company or Customer Meter Reading

1. The Company may, at its discretion, permit Customer reading of meters.
2. It will be the Company's responsibility to inform the Customer how to properly read his or her meter
3. Where a Customer reads his or her own meter the Company will read the Customer's meter at least once every four (4) months.
4. Where the Company must read the meter every four (4) months, the Customer shall pay Fee No. 3 as set forth in the UNS Electric Statement of Charges for every read.
5. The Company will provide the Customer with postage-paid cards or other methods to report the monthly meter reading to the Company.
6. The Company will specify the timing requirements for the Customer to submit his or her monthly meter reading to conform to the Company's billing cycle.
7. Meter readings will be scheduled for periods of not less than twenty-five (25) days or more than thirty-five (35) days. In the event the Customer fails to submit a reading within this ten (10) day period, the Company may issue the Customer an estimated bill.
8. In the event the Customer fails to submit monthly reads as designated above, the Company may estimate the usage for up to three (3) months.
9. The Company and the Customer shall mutually agree on a method to submit meter reads.
10. Where the Customer is providing their own meter reads, the Customer is responsible for all applicable charges as calculated from the point the Company last read the Customer's meter.
11. Meters will be read monthly on as close to the same day as practical.

B. Measuring of Service

1. All energy sold to Customers and all energy consumed by the Company – except that sold according to fixed charge schedules – will be measured by commercially acceptable measuring devices owned and maintained by the Company. This provision will not apply where it is impractical to install meters, such as street lighting or security lighting, or where otherwise authorized by the ACC.
2. When there is more than one meter at a location, the metering equipment will be so tagged or plainly marked as to indicate the circuit metered or metering equipment in accordance with Subsection 3.C.9.

SECTION 10
METER READING
(continued)

3. Meters which are not direct reading will have the multiplier plainly marked on the meter.

~~4. All charts taken from recording meters will be marked with the date of the record, the meter number, customer and chart multiplier.~~ The Company may employ meter reading technology that records interval data and displays total consumption.

4.

5. Metering equipment will not be set "fast" or "slow" to compensate for supply transformer or line losses.

C. Customer-Requested Rereads

1. The Company will, at the request of a Customer, reread that Customer's meter within ten (10) business days after that request by the Customer.

2. Any reread may be charged to the Customer, at a rate set forth as Fee No. 2 in the UNS Electric Statement of Charges, if the original reading was not in error.

3. When a reading is found to be in error, the Company will not charge the Customer for the reread.

D. Access to Customer Premises

The Company will at all times have the right of safe ingress to and egress from the Customer's premises at all reasonable hours for any purpose reasonably connected with the Company's property used in furnishing service and the exercise of any and all rights secured to it by law or these ~~R~~rules.

E. Meter Testing and Maintenance

1. The Company will replace any meter found to be damaged or associated with an inquiry into its accuracy, whether initiated by the Customer or Company, and which has been in service for more than sixteen years. Replaced meters will be tested for accuracy and will be acceptable if found to have an error margin within plus or minus three percent (±3%).

2. The Company will file an annual report with the Commission summarizing the results of meter maintenance and testing program for that year. At a minimum, the report should include the following data:

   a. Total number of meters tested at Company initiative or upon Customer request; and

   b. Number of meters tested that were outside the acceptable error allowance of ±3%.

SECTION 10
METER READING
(continued)

F. Customer-Requested Meter Tests

1. The Company will test a meter upon Customer request and the Company will be authorized to charge the Customer for the meter test. The charge for the meter test is set forth as Fee No. 7 in the UNS Electric Statement of Charges. However, if the meter is found to be in error by more than three percent (3%), no meter testing fee will be charged to the Customer.

G. Demands

1. The Customer's demand may be measured by a demand meter, under all Rates involving billings based on demand, unless appropriate investigation or tests indicate that the Customer's demand will not be such as to require a demand meter for correct application of the Rrate ~~schedule~~. In cases where billings under a Rrate ~~schedule~~ requiring determination of the Customer's demand must be made before a demand meter can be installed, these billings may be made on an estimated demand basis pending installation of the demand meter. Billings made on the basis of estimated demands; however, will be appropriately adjusted, if actual demands recorded after demand meter is installed is~~are~~ greater or less than those estimated demands.

2. Demand meters may be installed at any metering location if the nature of the Customer's equipment and operation indicates that a demand meter is required for correct application of the rate schedule.

3. All demands used for billing purposes will be recorded or computed to the nearest whole kW.

H. Automated Meter Opt-Out

Residential Service (RES-01) Customers may request meters that do not transmit data wirelessly and the Company will accommodate such requests to the extent practicable. The charge for the Special Meter Reading Fee is set forth as Fee No. 3 in the UNS Electric Statement of Charges. The charge for the Automated Meter Opt-Out Set-Up Fee is set forth as Fee No. 6 in the UNS Electric Statement of Charges.

SECTION 11
BILLING AND COLLECTIONS

A. Frequency and Estimated Bills

1. The Company will bill monthly for services rendered. Meter readings will be scheduled for periods of not less than twenty-five (25) days or more than thirty-five (35) days.

2. If the Company is unable to obtain the meter read on the scheduled meter read date, the Company will estimate the consumption for the billing period as set forth in the Company's Bill Estimation Methodologies Tariff.

3. Estimated bills will be issued only under the following conditions:

   a. Failure of a Customer who reads his or her own meter to deliver his or her meter reading card to the Company in accordance with the requirements of the billing cycle.

   b. Severe weather conditions which prevent the Company from reading the meter.

   c. Circumstances that make it dangerous or unnecessarily difficult to read the meter. These circumstances include, but are not limited to, locked gates, blocked meters, vicious or dangerous animals, or any force majeure condition as listed in Subsection 8.E.4.

   d. When an electronic meter reading is obtained, but the data cannot be transferred to a Customer Information System.

   e. A meter failure or malfunction with no reliable information retained by the meter.

   ~~e.~~f. A failure of the meter communication network preventing receipt of reliable information.

   ~~f.~~g. Meter tampering or energy diversion results in a lack of accurate metered consumption information.

   ~~g.~~h. In the event the Customer fails to submit the reading within the designated ten (10) day meter reading window.

   ~~h.~~i. In the event the Customer fails to submit monthly reads as designated above, the Company may estimate the usage for up to three (3) months.

4. After the second consecutive month of estimating the Customer's bill, the Company will attempt to secure an accurate reading of the meter.

5. Failure on the part of the Customer to comply with a reasonable request by the Company for access to its meter may lead to the discontinuance of service.

6. Each bill based on estimated usage will indicate that it is an estimated bill.

7. Estimates due to equipment malfunctions may exceed ~~one~~two months if the malfunction could not be reasonably discovered and/or corrected before additional bills were estimated.

8. A bill is not considered an estimated bill when the end read is based on an actual read.

SECTION 11
BILLING AND COLLECTIONS
(continued)

B. Combining Meters, Minimum Bill Information

1. Each meter at a Customer's premises will be considered separately for billing purposes, and the readings of two (2) or more meters will not be combined unless otherwise provided for in the Company's Rates.

2. Each bill for residential service will contain the following minimum information:

   a. Date and meter reading at the start of billing period or number of days in the billing period;
   b. Date and meter reading at the end of the billing period;
   c. Billing usage and demand (if applicable);
   d. Rate schedule number;
   e. Company's telephone number;
   f. Customer's name;
   g. Service account number;
   h. Amount due and due date;
   i. Past due amount;
   j. Purchased Power Fuel Adjuster Clause cost, where applicable;
   ~~j.~~k. Other ACC-approved charges;
   ~~k.~~l. All applicable taxes; and
   ~~l.~~m. The address for the Arizona Corporation Commission.

C. Billing Terms

1. All bills for electric service are due and payable no later than ten (10) days from the date the bill is rendered. Any payment not received within this time frame will be considered past due.

2. For purposes of this rule, the date a bill is rendered may be evidenced by:

   a. The postmark date for bills sent via U.S. Postal Service; or
   b. The mailing date; or
   c. The billing date shown on the bill (however, the billing date will not differ from the postmark or mailing date by more than two (2) days).
   d. An Electronic Bill will be considered rendered at the time it is electronically sent to the Customer.

SECTION 11
BILLING AND COLLECTIONS
(continued)

3. All past due bills for electric service are due and payable within fifteen (15) days. Any payment not received within this timeframe will be considered delinquent and will be issued a suspension of service notice. For Customers under the jurisdiction of a bankruptcy court, a more stringent payment or prepayment schedule may be required, if allowed by that court.

4. All delinquent bills for which a valid payment has not been received within five (5) days will be subject to the provisions of the Company's termination procedures.

5. The amount of the late payment penalty as set forth as Fee No. 10 in the UNS Electric Statement of Charges will not exceed one and one-half percent (1.5%) of the delinquent bill, applied on a monthly basis.

6. All payments must be made ~~at or sent via U.S. Postal Service to the Company's duly authorized representative~~by a payment method authorized by the Company.

7. A bill will be rendered in a form prescribed by the Company. If the Customer requests a bill in a form other than the one prescribed by the Company, the Company in its sole discretion may consider such request and charge the Customer any associated costs.

D. Applicable Rates, Prepayment, Failure to Receive, Commencement Date, Taxes

1. Each Customer will be billed under the applicable tariff indicated in the Customer's application for service.
2. Customers may pay for electrical service by making advance payments.
3. Failure to receive bills or notices that have been properly placed in the U.S. Postal Service or posted electronically will not prevent those bills from becoming delinquent nor relieve the Customer of his obligations therein.
4. Charges for service commence when the service is installed and connection made, whether used or not.

E. Meter Error Corrections

1. If any meter after testing is found to be more than three percent (3%) in error, either fast or slow, proper correction of the error will be made of previous readings and adjusted bills will be rendered according to the following terms:

   a. For the period of three (3) months immediately preceding the removal of such meter from service for test or from the time the meter was in service since last tested, but not exceeding three (3) months since the meter has been shown to be in error by the test; or

SECTION 11
BILLING AND COLLECTIONS
(continued)

b. From the date the error occurred, if the date of the cause can be definitely fixed. If the Customer has been underbilled, the Company will allow the Customer to repay this difference over the same~~an equal~~ period~~length~~ of time for which~~that~~ the under-billings occurred. The Customer may be allowed to pay the backbill without late payment penalties, unless there is evidence of meter tampering or energy diversion.

c. If it is determined that the Customer has been overbilled and there is no evidence of meter tampering or energy diversion, the Company will make prompt adjustment or refund in the difference between the original billing and the corrected billing within the next billing cycle.

2. No adjustment will be made by the Company except to the Customer last served by the meter tested.

F. Responsibility for Payment of Bills

1. The Customer is responsible for the payment of bills until service is ordered discontinued and the Company has had reasonable time to secure a final meter reading for those services involving energy usage, or if non-metered services are involved until the Company has had reasonable time to process the disconnect request.

2. When an error is found to exist in the billing rendered to the Customer, the Company shall correct such an error to refund any overbilling and may correct such an error to recover any underbilling. The UNS Electric Bill Estimation Methodologies tariff shall be applied when the Company cannot obtain a complete and valid meter read. Situations that result in an estimated meter read include inclement weather, lack of access to a Customer's meter, energy diversion, labor unavailability and equipment malfunction.

3. Except as specified below, corrected charges for underbillings shall be limited to three (3) months for residential accounts and six (6) months for non-residential accounts.

   a. Where the account is billed on a special contract or non-metered rate, corrected charges for underbillings shall be billed in accordance with the contract or rate requirements and is not limited to three or six months as applicable.

   b. Where service has been established but no bills have been rendered, or a bill is rendered, but shows no consumption, corrected charges for underbillings shall go back to the date service was established.

   c. Where there is evidence of meter tampering or energy diversion, corrected charges for underbillings shall go back to the date meter tampering or energy diversion began, as determined by the Company.

   d. Where lack of access to the meter (caused by the Customer) has resulted in estimated bills, corrected charges for underbillings shall go back to the billing month of the last Company obtained meter read date.

SECTION 11
BILLING AND COLLECTIONS
(continued)

G. Returned Payments

1. The Company will be allowed to recover a fee, as set forth as Fee No. 9 in the UNS Electric Statement of Charges, for each instance where a Customer tenders payment for electric service with a payment returned unpaid. This fee will also apply when an electronic funds transfer ("EFT") is denied for any reason.

2. When the Company is notified by the Customer's bank or other financial institution that a payment has been returned unpaid, or denied for any reason, the Company may require the Customer to make payment in cash, by money order~~, certified check,~~ or other ~~means~~ approved methods which guarantee the Customer's payment to the Company.

3. A Customer, who tenders a payment which is returned unpaid, regardless of the reason or method used to pay, will not be relieved of the obligation to render payment to the Company under the original terms of the bill nor defer the Company's provision for termination of service for nonpayment of bills.

4. A Customer with two (2) returned payments within a twelve (12) month period may be required to pay with guaranteed funds, (i.e., cash, money order, or other approved methods~~cashier's check~~ for any subsequent billing for twelve (12) months.

H. Budget Billing Plan

1. The Company may, at its option, offer its Customers a budget billing plan.

2. ~~The Company will develop, upon Customer request, an estimate of the Customer's budget billing for a twelve (12)-month period based upon~~The Company will provide, upon Customer request, an estimate of the Customer's budget billing amount for a twelve-month period based upon:

   a. Customer's actual consumption history, which may be adjusted for abnormal conditions such as weather variations;

   b. For new Customers, the Company will estimate consumption based on the Customer's anticipated load requirements; or

   c. The Company's Rates approved by the ACC applicable to that Customer's class of service.

3. The Company will provide the Customer, upon Customer request, a concise explanation of how the budget billing estimate was developed, the impact of budget billing on a Customer's monthly bill, and the Company's right to adjust the Customer's billing for any variation between the Company's estimated billing and actual billing.

SECTION 11
BILLING AND COLLECTIONS
(continued)

4. For those Customers being billed under a budget billing plan, the Company will show, at a minimum, the following information on the Customer's monthly bill:

   a. Actual consumption;

   b. Amount due for actual consumption;

   c. Budget billing amount due; and

   d. Accumulated variation in actual versus budget billing amount.

5. ~~The Company may adjust the Customer's budget billing in the event the Company's estimate of the Customer's usage and/or cost should vary significantly from the Customer's actual usage and/or cost; such review to adjust the amount of the budget billing may be initiated by the Company or upon Customer request.~~The Company may adjust the Customer's budget billing in the event the Company's estimate of the Customer's usage and/or cost varies significantly from the Customer's actual usage and/or cost. This review to adjust the amount of the budget billing may be initiated by the Company or the Customer.

6. While on the budget billing plan, the Customer shall pay the monthly plan amount , notwithstanding the current charges shown on the bill.

7. Any other charges incurred by the Customer shall be paid when due in addition to the monthly plan amount.

~~5.~~8. Interest will not be charged to the Customer on accrued debit balances nor paid by the Company on accrued credit balances.

I. Deferred Payment Plan

1. The Company may, prior to termination of service, offer to qualifying Customers a deferred payment plan for the Customer to retire unpaid delinquent bills for electric service.

2. Each deferred payment agreement entered into between the Company and the Customer – due to the Customer's inability to pay an outstanding bill in full – will specify that service will not be discontinued if:

   a. Customer agrees to pay a reasonable amount of the outstanding bill at the time the parties enter into the deferred payment agreement;

   b. Customer agrees to pay all future bills for electric service in accordance with the Company's Rates; and

   c. Customer agrees to pay a reasonable portion of the remaining outstanding balance in installments over a period not to exceed ~~six (6)~~three (3) months.

SECTION 11
BILLING AND COLLECTIONS
(continued)

3. For the purpose of determining a reasonable installment payment schedule, under these rules, the Company and the Customer will give consideration to the following conditions:

   a. The size of the delinquent account;

   b. The Customer's ability to pay;

   c. The Customer's payment history;

   d. The length of time that the debt has been outstanding;

   e. The circumstances that resulted in the debt being outstanding; and

   f. Any other relevant factors related to the circumstances of the Customer.

4. Any Customer who desires to enter into a deferred payment agreement must do so before the Company's scheduled termination date for nonpayment of bills. The Customer's failure to execute a deferred payment agreement prior to the scheduled service termination date will not prevent the Company from terminating service for nonpayment.

5. Deferred payment agreements may be in writing and may be signed by the Customer and an authorized Company representative.

6. A deferred payment agreement ~~may include a finance charge of one and one-half percent (1.5%)~~does not relieve the unpaid balance from being assessed a monthly late charge, in accordance with the current late payment fee percentage rate.

7. If a Customer has not fulfilled the terms of a deferred payment agreement, the Company will have the right to disconnect service pursuant to the Company's Termination of Service Rules (Section 12) and, under these circumstances, it will not be required to offer subsequent negotiation of a deferred payment agreement prior to disconnection.

J. Change of Occupancy

1. To order service to be discontinued or to change occupancy, the Customer must give the Company at least three (3) business days advance notice via the website, e-mailin ~~person~~, in writing or by telephone.

2. The outgoing Customer will be responsible for all electric services provided and/or consumed up to the scheduled turn-off- date.

3. The outgoing Customer or property owner, in the case of a known landlord/tenant situation, is responsible for providing access to the meter so that the Company may obtain a final meter reading. If access is unavailable, due to the action or inaction of the Customer or property owner, the outgoing Customer or owner/landlord will be

responsible for the services consumed until such time as access is provided and services can be disconnected ~~turned-off~~.

SECTION 11
BILLING AND COLLECTIONS
(continued)

K. Electronic Billing

1. Electronic Billing is an optional billing service whereby Customers may elect to receive, view, and pay their bills electronically. Electronic Billing includes the "UES e-bill" service ~~and the Automatic Payment ("Auto Pay") service~~with a no-fee payment option. The Company may modify its Electronic Billing services from time to time. A Customer electing an electronic billing service may receive an electronic bill in lieu of a paper bill.

2. Customers electing an electronic billing service may be required to complete additional forms and agreements.

3. Electronic Billing may be discontinued at any time by the Company or the Customer.

4. An Electronic Bill will be considered rendered at the time it is electronically sent to the Customer. Failure to receive bills or notices which have been properly sent by an Electronic Billing system does not prevent these bills from becoming delinquent and does not relieve the Customer of the Customer's obligations therein.

5. Any notices that the Company is required to send to a Customer who has elected an Electronic Billing service may be sent by electronic means at the option of the Company.

6. Except as otherwise provided in this subsection, all other provisions of the Company's Rules and Regulations and other applicable Rates are applicable to Electronic Billing.

7. The Customer must provide the Company with a current email address for electronic bill delivery. If the Electronic Bill is electronically sent to the Customer at the email address that Customer provided to the Company, then the Electronic Bill will be considered properly sent. Further, the Customer will be responsible for updating the Company with any changes to this email address. Failure to do so will not excuse the Customer from timely paying the Company for electric service.

L. Collections

1. All unpaid closed accounts may be referred to a collection agency for collections.

2. If a collection agency referral is warranted for collection of unpaid final bills, Customer will be responsible for associated collection agency fees ~~incurred~~assessed. If the unpaid bill is referred to a credit bureau, the Company will not be held responsible to notify the Credit Bureau of any payment status.

M. Refunds

Customers will not be eligible for refunds, rebates or other Company program payments if the Customer has a delinquent Company balance.

SECTION 11
BILLING AND COLLECTIONS
(continued)

N. Refund of Credit Balance Following Discontinuance of Service

Upon discontinuance of service, the Company shall refund the Customer any credit balance remaining on the account. With the consent of the Customer (when available), any credit balance remaining on the account that is less than $5.00, shall be donated to a low-income assistance program to be determined by the Company or as may be required by law.

SECTION 12
TERMINATION OF SERVICE

A. Please refer to the Arizona Administrative Code R14-2-211.A.

B. Termination of Service Without Notice

1. The Company may disconnect electric service without advance written notice under the following conditions:

   a. The existence of an obvious hazard to the safety or health of the Customer or the general population or the Company's personnel or facilities;

   b. The Company has evidence of meter tampering or fraud; or

   c. The Company has evidence of unauthorized resale or use of electric service; or

   d. Customer makes payment to avoid/stop disconnection for non-payment with a dishonored or fraudulent payment. The Company will not be required to restore service until the repayment of those funds and all other delinquent amounts are paid by cash, money order, cashier's check, certified funds or verified electronic payment; or

   e. Customer makes payment to reconnect service with a dishonored or fraudulent payment. The Company will not be required to restore service until the repayment of those funds and all other delinquent amounts are paid by cash, money order, cashier's check, certified funds or verified electronic payment; or

   f. Failure of a Customer to comply with the curtailment procedures imposed by the Company during supply shortages.

2. The Company will not be required to restore service until the conditions that led to the termination have been corrected to the satisfaction of the Company.

3. The Company will maintain a record of all terminations of service without notice. This record will be maintained for a minimum of one (1) year and will be available for inspection by the ACC.

C. Termination of Service With Notice

1. The Company may disconnect service to any Customer for any reason stated below, provided that the Company has met the notice requirements described in subsection 12.D. below:

   a. Customer violation of any of the Company's Rates;

   b. Failure of the Customer to pay a delinquent bill for electric service;

   c. Failure of a prior Customer to pay a delinquent bill for electric service where the prior Customer continues to reside on the premise;

   d. Failure of the Customer to meet agreed-upon deferred payment arrangements;

SECTION 12
TERMINATION OF SERVICE
(continued)

e. Failure to meet or maintain the Company's deposit requirements;

f. Failure of the Customer to provide the Company reasonable safe access to its equipment and property;

g. Customer breach of a written contract for service between the Company and Customer;

h. Returned or invalid payment;

i. When necessary for the Company to comply with an order of any governmental agency having jurisdiction;

j. When a hazard exists which is not imminent, but in the opinion of the Company, it may cause property damage;

k. Customer facilities that do not comply with Company requirements or specifications;

l. Failure to provide or retain rights-of-way or easements necessary to serve the Customer;

m. The Company learns of the existence of any condition in Section 3.D., Grounds for Refusal of Service.

2. The Company will maintain a record of all terminations of service with notice. This record will be maintained for one (1) year and be available for ACC inspection.

D. The Company will not be obligated to renotify the Customer of the termination of service, even if the Customer – after receiving the required termination of service notification – has made payment, yet the payment is returned within three (3) to five (5) business days of receipt for any reason. The original notification will apply.

E. Termination Notice Requirements

1. The Company will not terminate service to any of its Customers without providing advance written notice to the Customer of the Company's intent to disconnect service, except under these conditions specified in subsection 12.A. where advance written notice is not required.

2. This advance written notice will contain, at a minimum, the following information:

a. The name of the person whose service is to be terminated and the address where service is being rendered;

b. The Company's Rate(s) that was violated and explanation of the violation or the amount of the bill that the Customer has failed to pay in accordance with the payment policy of the Company, if applicable;

c. The date on or after which service may be terminated;

d. A statement advising the Customer to contact the Company at a specific phone number for information regarding any deferred payment or other procedures that the Company may offer or to work out some mutually agreeable solution to avoid termination of the Customer's service; and;

SECTION 12
TERMINATION OF SERVICE
(continued)

e. A statement advising the Customer that the Company's stated reason(s) for the termination of services may be disputed by contacting the Company at a specific address or phone number, advising the Company of the dispute and making arrangements to discuss the cause for termination with a responsible employee of the Company in advance of the scheduled date of termination. The responsible employee will be empowered to resolve the dispute and the Company will retain the option to terminate service after affording this opportunity for a meeting and concluding that the reason for termination is just and advising the Customer of his or her right to file a complaint with the ACC.

3. Where applicable, a copy of the termination notice will be simultaneously forwarded to designated third parties.

F. Timing of Terminations with Notice

1. The Company will give at least five (5) days advance written notice prior to the termination date. For Customers under the jurisdiction of a bankruptcy court, a shorter notice may be provided, if permitted by the court.

2. This notice will be considered to be given to the Customer when a copy of the notice is left with the Customer or posted first class via the U.S. Postal Service, addressed to the Customer's last known address.

3. If, after the period of time allowed by the notice has elapsed and the delinquent account has not been paid nor arrangements made with the Company for the payment of the bill – or in the case of a violation of the Company's rules the Customer has not satisfied the Company that this violation has ceased – then the Company may terminate service on or after the day specified in the notice without giving further notice.

4. The Company will have the right (but not the obligation) to remove any or all of its property installed on the Customer's premises upon the termination of service.

G. Landlord/Tenant Rule

In situations where service is rendered at an address different from the mailing address of the bill or where the Company knows that a landlord/tenant relationship exists and that the landlord is the Customer of the Company, and where the landlord as a Customer would otherwise be subject to disconnection of service, the Company will not disconnect service until the following actions have been taken:

1. Where it is feasible to so provide service, the Company will offer the occupant the opportunity to subscribe for service in the occupant's own name. If the occupant then declines to so subscribe, the Company may disconnect service pursuant to the rules.

2. The Company will not attempt to recover from a tenant or condition service to a tenant with the payment of any outstanding bills or other charges due upon the outstanding account of the landlord.

SECTION 12
TERMINATION OF SERVICE
(continued)

H.

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 a 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.

SECTION 13
RECONNECTION OF SERVICE

When service has been discontinued for any of the reasons set forth in these Rules and Regulations, the Company will not be required to restore service until the following conditions have been met by the Customer:

A. Where service was discontinued without notice:

1. The hazardous condition must be removed and the installation will conform to accepted standards.
2. All bills for service and/or applicable investigative costs due the Company by reason of fraudulent or unauthorized use, diversion or tampering must be paid and a deposit to guarantee the payment of future bills may be required.
3. Required arrangements for service must be made.

B. Where service was discontinued with notice:

1. The Customer must make arrangements for the payment of all bills and these arrangements must be satisfactory to the Company.
2. The Customer must furnish a satisfactory guarantee to pay all future bills.
3. The Customer must correct any and all violations of these Rules and Regulations.

SECTION 14
ADMINISTRATIVE AND HEARING REQUIREMENTS

A. Customer Service Complaints

1. The Company will make a full and prompt investigation of all service complaints made by its Customers, either directly or through the ACC.

2. The Company will respond to the complainant and/or the ACC representative within five (5) business days as to the status of the Company's investigation of the complaint.

3. The Company will notify the complainant and/or the ACC representative of the final disposition of each complaint. Upon request of the complainant or the ACC representative, the Company will report the findings of its investigation in writing.

4. The Company will inform the Customer of his right of appeal to the ACC.

5. The Company will keep a record of all written service complaints received that must contain, at a minimum, the following data:

   a. Name and address of complainant;

   b. Date and nature of the complaint;

   c. Disposition of the complaint; and

   d. A copy of any correspondence between the Company, the Customer, and/or the ACC.

6. This record will be maintained for a minimum period of one (1) year and will be available for inspection by the ACC.

B. Customer Bill Disputes

1. Any Customer who disputes a portion of a bill rendered for electric service must pay the undisputed portion of the bill and notify the Company's designated representative that any unpaid amount is in dispute prior to the delinquent date of the bill.

SECTION 14
ADMINISTRATIVE AND HEARING REQUIREMENTS
(continued)

2. Upon receipt of the Customer notice of dispute, the Company will:

   a. Notify the Customer within five (5) business days of the receipt of a written dispute notice;

   b. Initiate a prompt investigation as to the source of the dispute;

   c. Withhold disconnection of service until the investigation is completed and the Customer is informed of the results;

   d. Upon request of the Customer the Company will report the results of the investigation in writing; and

   e. Inform the Customer of his right of appeal to the ACC.

3. Once the Customer has received the results of the Company's investigation, the Customer will submit payment within five (5) business days to the Company for any disputed amounts. Failure to make full payment will be grounds for termination of service.

C. ACC Resolution of Service and/or Bill Disputes

1. In the event a Customer and the Company cannot resolve a service and/or bill dispute, the Customer will file a written statement of dissatisfaction with the ACC. By doing this, the Customer will be deemed to have filed an informal complaint against the Company.

2. Within thirty (30) days of the receipt of a written statement of Customer dissatisfaction related to a service or bill dispute, a designated representative of the ACC will attempt to resolve the dispute by correspondence and/or telephone with the Company and the Customer. If resolution of the dispute is not achieved within twenty (20) days of the ACC representative's initial effort, the ACC will then hold an informal hearing to arbitrate the resolution of the dispute. The informal hearing will be governed by the following rules:

   a. Each party may be represented by legal counsel, if desired;

   b. Every informal hearing may be recorded or held in the presence of a stenographer;

   c. All parties will have the opportunity to present written or oral evidentiary material to support the positions of the individual parties;

   d. All parties and the ACC's representative will be given the opportunity for cross-examination of the various parties; and

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(continued)

e. The ACC's representative will render a written decision to all parties within five (5) business days after the date of the informal hearing. This written decision of the ACC's representative is not binding on any of the parties and the parties will still have the right to make a formal complaint to the ACC.

3. The Company may implement normal termination procedures if the Customer fails to pay all bills rendered during the resolution of the dispute by the ACC.

4. The Company will maintain a record of written statements of dissatisfaction and their resolution for a minimum of one (1) year and make these records available for ACC inspection.