NEW APPLICATION

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BEFORE THE ARIZONA CORPORATION COMMISSION

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

Arizona Corporation Commission
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UNS ELECTRIC, INC.

APPLICATION
TESTIMONY AND EXHIBITS

VOLUME 1 of 4

MAY 5, 2015

UNS Electric, Inc.
New Application

E-04204A-15-0142

PART 1 OF 3
BARCODE # 0000161983

To review Part 2 please see:
BARCODE # 0000161984

To review Part 3 please see:
BARCODE # 0000161985

Application

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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. <u>APPLICATION</u>.

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:

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and

Michael W. Patten
Jason D. Gellman
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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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Original and 13 copies of the foregoing filed this 5th day of May 2015, with:

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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

Direct Testimony of
David G. Hutchens

BEFORE THE ARIZONA CORPORATION COMMISSION

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

Direct Testimony of

David G. Hutchens

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 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

[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]

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[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.

[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.

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[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.

[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.

Direct Testimony of
Terry Nay

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

TABLE OF CONTENTS

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.

Direct Testimony of
Michael E. Sheehan

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.

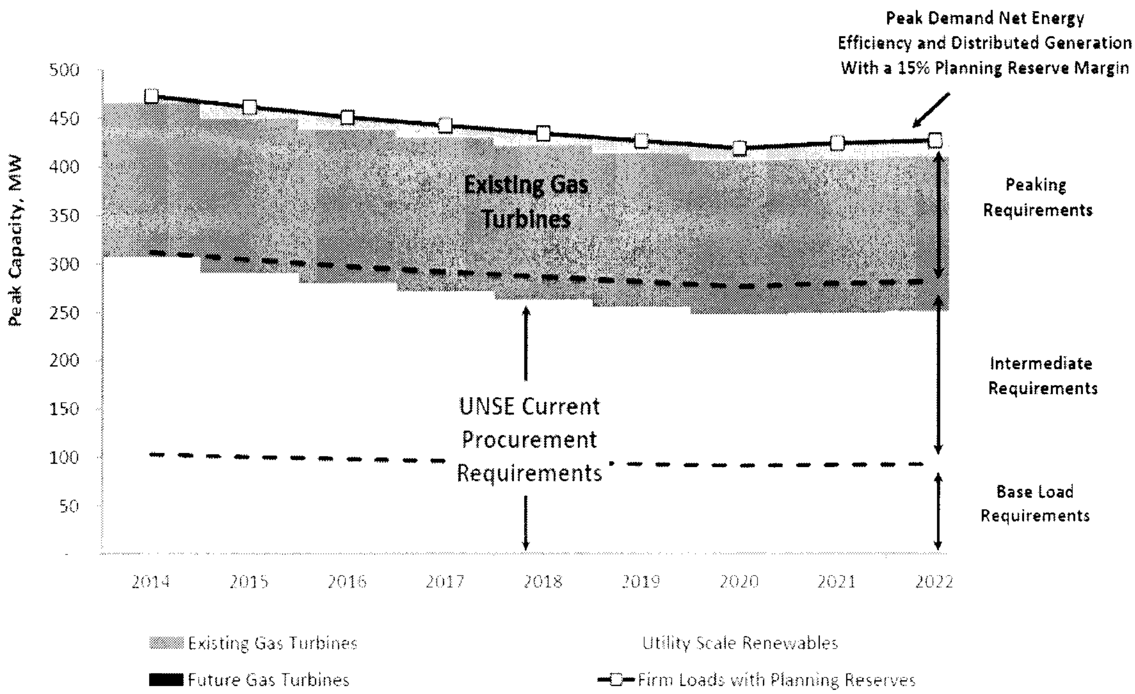
A. UNS Electric provides electricity to approximately 93,000 customers in two geographically distinct areas. In northwest Arizona, UNS Electric provides service to the majority of Mohave County. This segment of the service territory includes approximately 73,000 customers located primarily in the Kingman 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

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[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.

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[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.

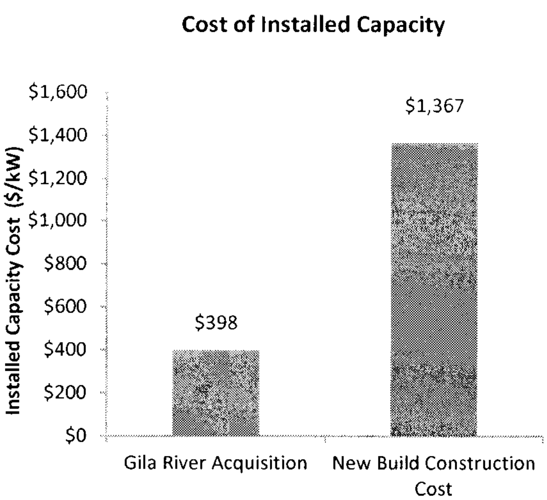
levelized cost for Gila River is estimated at approximately $79.72/MWh whereas the levelized cost for new build construction is estimated at $117.40/MWh. In addition, UNS Electric's share of Gila River is much less expensive than a similar commitment in a newly constructed combined cycle plant. The Gila 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.

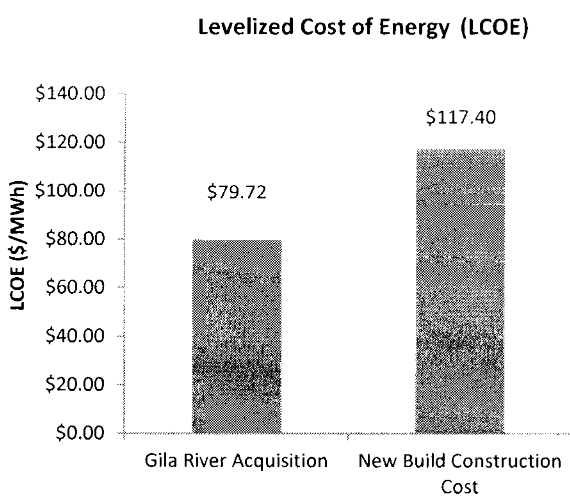
Exhibit 1 - Gila River vs. New Construction Cost Comparison[10]

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.

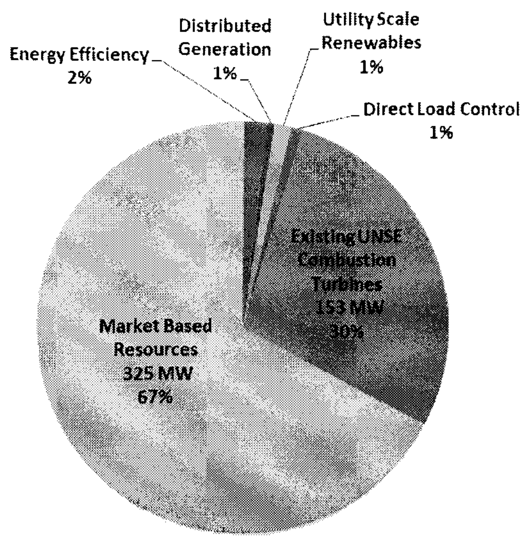
[13] Hypothetical market based acquisition savings - \$26,950,000 = (594 \$/KW - 398 \$/kW) * 137,500 kW.

V. GILA RIVER UNIT 3'S IMPACT ON PORTFOLIO DIVERSIFICATION.

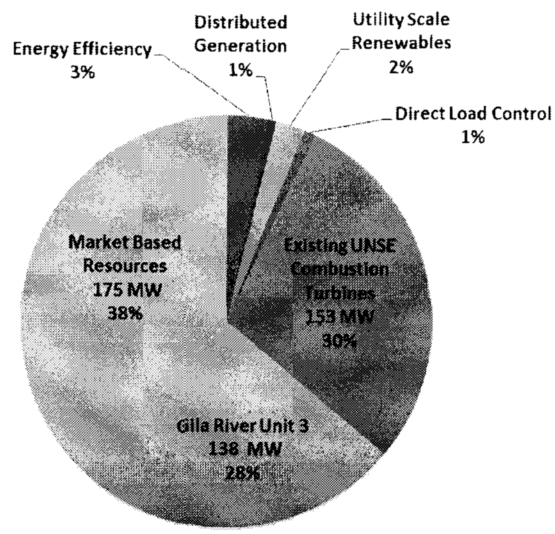
Q. Can you summarize UNS Electric's resource capacity before and after the acquisition of Gila River?

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 <u>Prior</u> to Gila River Acquistion



UNSE Capacity <u>After</u> 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:

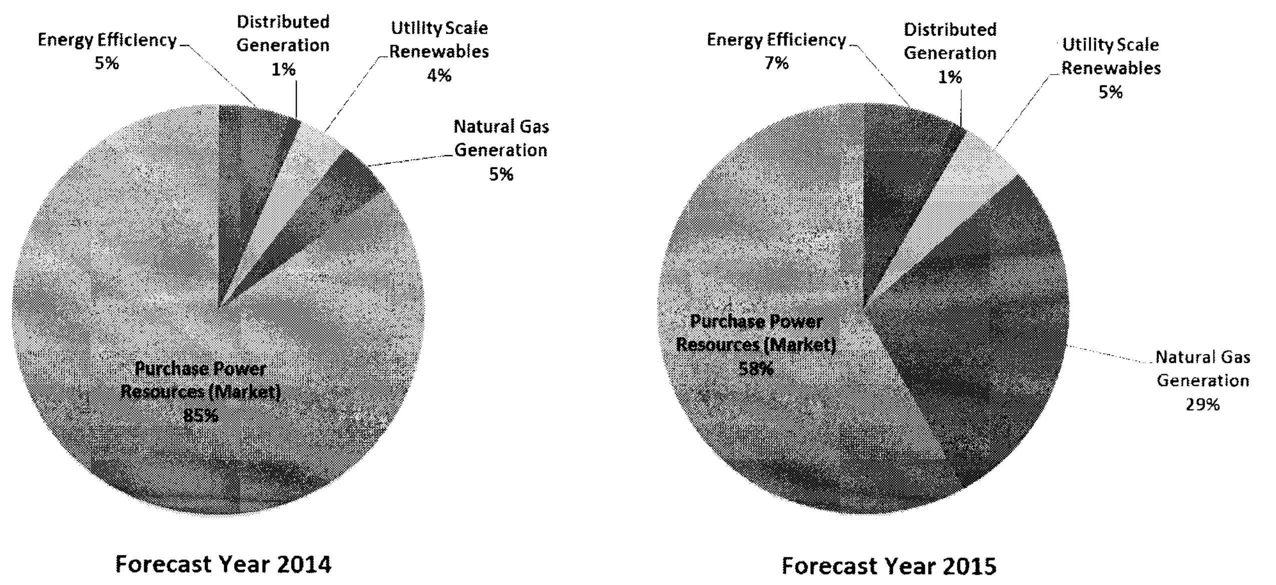
[14] 2014 UNS Electric Integrated Resource Plan at 248.

"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.

[23] Staff Report, Attachment A, (Engineering Analysis) at 12 (UNS Electric Inc. Financing Application (Docket No. E-04204A-13-0447)).

Direct Testimony of
Carmine Tilghman

BEFORE THE ARIZONA CORPORATION COMMISSION

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UNS Electric, Inc.

May 5, 2015

Q. Please state your name and business address.

A. Carmine Tilghman, 88 East Broadway, Tucson, Arizona 85702.

Q. By whom are you employed and in what capacity?

A. I am the Senior Director of Renewable Resources and Programs for UNS Electric ("UNS Electric" or "the Company") and Tucson Electric Power Company ("TEP").

Q. Please describe your background and work experience.

A. I served in the United States Navy from 1984–1993 as a Nuclear Reactor Operator in Submarine Service. From 1993-1995, I worked as a Power Plant Operator for the Biosphere II Project in Oracle, Arizona.

I was hired by TEP in 1995 as a Power Plant Operator. In 1996, I moved into TEP's Wholesale Marketing Department where I held several positions in Energy Trading, Marketing, Project Management, and Scheduling before being promoted to Supervisor/Manager in 2003. From 2003-2008, I held supervisory positions in Trading, Scheduling, and Procurement before taking over Utility Scale Renewable Energy Development in 2008.

In 2010, I took over all aspects of renewable energy development for both TEP and UNS Electric, Inc. In my current position, I am responsible for the renewable resources and renewable resource programs for the Companies, including compliance with the Arizona Corporation Commission's ("Commission") Renewable Energy Standard and Tariff Rules ("REST Rules") (A.A.C. R14-2-1801 through R14-2-1818). In 2013, I added oversight of the Wholesale Marketing department to my duties, and in 2014 was promoted to Senior Director.

I received my Bachelor of Science in Business Management from the University of Phoenix in 2000 and Master of Business Administration from the University of Phoenix in 2002.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss: (1) the Company's investment in renewable generation resources since its last rate case; (2) the Company's request to transfer into base rates those costs of Company-owned renewable generation resources since the last rate case in accordance with prior Commission orders; (3) provide a general discussion regarding the impacts of renewable energy, particularly solar and distributed generation ("DG") resources, on the utility's operations; and (4) the Company's proposed changes to its present net metering tariff.

Q. What is the approximate investment the Company has made on utility-owned renewable resources?

A. In the Company's 2010 rate case, UNS Electric was authorized to invest up to $5 million annually in utility-owned renewable energy projects from 2011 through 2014. The Company subsequently received authorization from the Commission to invest an additional $5 million annually for the years 2015 and 2016. In total, the Company has invested about $20 million in utility-owned renewable generation.

Q. How much of the Company's investment in renewable generation was included the rate base approved in UNS Electric's last rate case?

A. The approximate $5 million invested in 2011 was included in the Company's last general rate case.

Q. Please describe the renewable resource investments the Company added to the rate base requested in this filing.

A. Since the last rate case, the Company invested $13.6 million in the 7.2 MW-dc fixed photovoltaic facility in Rio Rico, Arizona.

Q. Please describe UNS Electric's utility scale renewable portfolio, including both utility-owned facilities and power purchase agreements.

A. The Company currently owns two solar facilities totaling 8.42 MW-dc, including the 7.2 MW-dc Rio Rico facility described above and the 1.22 MW-dc located in Kingman, AZ.).

The Company is under contract to purchase the output from systems with a total combined capacity of 20.4 MW, including 10 MW-ac wind from the Western Wind wind/solar facility in Kingman, 0.5 MW-dc solar from the Western Wind wind/solar facility, and 9.9 MW-dc from the Black Mountain Solar Facility.

Using a 0.8 DC to AC conversion factor, the Company has ownership of 26.9% of its utility scale renewable energy portfolio.

Q. How has the rate of residential DG applications and installations changed since up-front incentives were eliminated by the Commission?

A. Since up-front incentives were eliminated in June 2014, residential applications for solar DG systems have actually *increased* by more than 25% per month, year over year. System size has also increased from an average of 7.93 kW in June 2014 to 9.09 kW as of March 2015.

The Commercial DG market has not been active in the Company's service territory since the incentives were eliminated, although there has been recent activity in Santa Cruz County.

When the residential solar market was effectively controlled by the amount of incentives provided through the REST, the annual installed capacity was roughly 1 MW, which met the incremental RPS requirement each year. However, the proliferation of the solar leasing model and the continued decline in solar panel prices, coupled with policies such as net metering, has effectively tripled the market penetration even though all utility incentives have been eliminated.

Q. From a grid operations perspective, what are the biggest challenges to integrating distributed generation, particularly solar?

A. DG has number of well-documented integration issues that can be placed into three categories: 1) intermittent generation; 2) inability to monitor and control systems; and 3) excess generation flowing back onto grid.

1) **Intermittent Generation.** The intermittency of renewable generation has long been discussed as the major drawback of renewable energy as customers are accustomed to – and insist on – continuous, reliable power. In order to firm up the intermittency and meet the customers' expectations, it requires the continued services of the centralized grid to supply the necessary back-up energy and ancillary services to support solar and other intermittent renewable resources. This problem is exacerbated through policies such as net metering, which encourages customers to oversize their solar systems beyond their average load in order to "bank" as many credits as possible for use later. This results in excessive

renewable capacity that requires the centralized grid's existing facilities to adjust to generation fluctuations created during solar production.

This is a growing problem for UNS Electric, as the company relies on its sister company, TEP, to provide balancing authority services through a Control Area Services Agreement. Effectively, TEP dynamically meters UNS Electric's entire load and provides all of the necessary ancillary services (unless UNS Electric can economically self-generate and provide these services). These services include load balancing, frequency support, voltage support, and spinning and non-spinning reserves. Increased intermittent generation creates greater load imbalance and fluctuations in voltage and frequency requiring additional ancillary services. Ultimately, updated rate design and large scale energy storage facilities on a system-wide basis will likely be needed to manage this issue.

2) **Inability to Monitor and Control Systems.** The inability to monitor and control systems is a growing source of concern for utilities. Operationally, distributed generation is not connected to a utilities' energy management system. As such, the utility has no ability to see the output or control the inverter. In essence, the utility is "driving blind" when it comes to distributed generation. In small quantities, distributed generation can be ignored. However, as the aggregated amount of distributed generation becomes larger, it represents a large generation source that the utility cannot see, has no control over, provides no ancillary services for, and can create significant load to generation imbalances.

3) **Excess Energy.** The excess energy flowing back onto the grid, a result of net metering policies, creates additional issues on the distribution system beyond the

cost-shifting issues discussed in the Direct Testimony of Dallas Dukes. Historically, the grid was designed to meet the peak needs of the customers on a particular distribution circuit, from the substation to the feeder to the shared transformers. However, under current net metering rules the customer can generate up to 125% of their connected load annually. Most customers attempt to generate between 90%-100%. In order to accomplish this through solar generation, the system is designed to be approximately double the customer's peak load. When multiple customers on a single transformer or feeder circuit have systems sized as such, the circuits' capacity rating can be exceeded. While the impacts of this issue are being studied in Hawaii, who has the largest distributed generation penetration of any utility, there are other issues more unique to the Company. Specifically, there are three issues of concern operationally beyond simply operating at an "over-capacity" rating:

A) Significantly higher energy flows resulting in increased operations and maintenance costs, and equipment wear and tear.

B) Excess energy does not always "flow to the next door neighbor" as is often quoted. During times of high export and low customer load, neighbors of exporting customers often have low usage as well, resulting in the energy flowing back up through the distribution system.

C) While high penetration of DG can help relieve feeder and circuit overload conditions during peaking months, the resulting over-generation and higher exports during the shoulder months often results in reverse power flow and overload conditions.

Q. Please provide a description of the Company's proposed changes to the current net metering tariff?

A. The proposed changes to the Net Metering tariff are twofold: a request for a new net metering tariff that provides monthly bill credits at a "Renewable Credit Rate" for excess energy produced and pushed on to the grid from a customer's solar system; and a partial waiver of the Net Metering Rules to eliminate the "roll over" of excess generation to offset future usage, as is currently prescribed in A.A.C. R14-2-2306.

Q. Please describe the Renewable Credit Rate.

A. UNS Electric is proposing to eliminate the requirement to provide DG customers with a full retail credit for all excess energy pushed back onto the grid and "banking" it for future use. While the customer can still offset their energy usage on a real time basis at the full retail rate any excess production from their system would be purchased by the Company at the Renewable Credit Rate. The Renewable Credit Rate – currently proposed to be 5.84 cents per kWh – is equivalent to the most recent utility scale renewable energy purchased power agreement connected to the distribution system of UNS Electric's affiliate, TEP. Although the Company has received lower priced offers from reputable and qualified development companies, the 5.84 cents per kWh is the price for a project currently under construction and scheduled to be completed in 2015. As such, the Company believes this represents the most accurate cost-based proxy.

Since both TEP and UNS Electric share a common balancing authority, as well as the ability to transfer energy between transmission and distribution systems, this value also represents the price that UNS Electric can purchase renewable energy on its distribution system. As the ratepayers ultimately pay the difference between conventional energy prices and renewable energy prices, the Company believes it is appropriate that net metered customers receive the same financial compensation for their distributed energy that is available from other, larger, more cost-effective resources.

Q. Will the Renewable Credit Rate Change?

A. Yes. The Company would file an annual Renewable Credit Rate similar to the Company's existing annual Market Cost of Comparable Conventional Generation (MCCCG) filing. This filing would be made with the annual REST filing based on the most recent comparable utility scale purchased power agreement for renewable energy that is connected to the Company's or TEP's distribution system.

Q. How will the Company purchase the excess energy produced by the Net Metering customer's facility?

A. Net Metering customers would be compensated for any excess energy their DG facility produces and delivers to UNS Electric with a credit on their monthly UNS Electric bill using the Renewable Credit Rate. Net Metering customers could carry over unused bill credits to future months if they exceed the amount of their current bill.

Q. Would the proposed tariff apply to current Net Metering customers?

A. No. All existing DG Customers would be grandfathered under the existing net metering tariff. The new Net Metering tariff would apply to customers who submit a completed application for interconnection to UNS Electric's grid facilities after June 1, 2015.

Q. Customers with DG systems undertake a significant capital investment to reduce their electric bills. How would this proposal impact their potential savings?

A. Under this proposal, DG customers would still see significant savings on their electric bills as described in Dallas Dukes' testimony. Moreover, if customers "right size" and do not overinvest in their systems, they should not be as impacted by updated net metering tariffs or rate designs as it relates to return on their investment.

Q. Does that conclude your direct testimony?

A. Yes.

Direct Testimony of
Kentton C. Grant

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

Kentton C. Grant

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 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.

Direct Testimony of
Ann E. Bulkley

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.	DOCKET NO. E-04204A-15-______

Direct Testimony of

Ann E. Bulkley

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 Ann E. Bulkley. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. What is your position with Concentric Energy Advisors, Inc. ("Concentric")?

A. I am employed by Concentric as a Vice President.

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

A. I am submitting this Direct Testimony on behalf of UNS Electric, Inc. ("UNS Electric" or the "Company"). UNS Electric is a wholly-owned subsidiary of UniSource Energy Services, an intermediate holding company owned by UNS Energy Corporation ("UNS Energy"). UNS Energy was purchased in August 2014 by Fortis, Inc. ("Fortis"). Fortis is an investor-owned utility holding company based in St. John's, Newfoundland and Labrador, Canada.

Q. Please describe your education and experience.

A. I hold a Bachelor's degree in Economics and Finance from Simmons College and a Master's degree in Economics from Boston University, with approximately 20 years of experience consulting to the energy industry. I have advised numerous energy and utility clients on a wide range of financial and economic issues with primary concentrations in valuation and utility rate matters. Many of these assignments have included the determination of the cost of capital for valuation and ratemaking purposes. I have included my resume and a summary of testimony that I have filed in other proceedings as Attachment A.

Q. Please describe Concentric's activities in energy and utility engagements.

A. Concentric provides financial and economic advisory services to many and various energy and utility clients across North America. Our regulatory, economic, and market analysis services include utility ratemaking and regulatory advisory services; energy market assessments; market entry and exit analysis; corporate and business unit strategy development; demand forecasting; resource planning; and energy contract negotiations. Our financial advisory activities include buy and sell-side merger, acquisition and divestiture assignments; due diligence and valuation assignments; project and corporate finance services; and transaction support services. In addition, we provide litigation support services on a wide range of financial and economic issues on behalf of clients throughout North America.

II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q. What is the purpose of your Direct Testimony?

A. The purpose of my Direct Testimony is to present evidence and provide a recommendation regarding the Company's return on equity ("ROE") [1] and to provide an assessment of the capital structure to be used for ratemaking purposes as proposed in the Direct Testimony of Company Witness Kentton C. Grant. My Direct Testimony also provides evidence and a recommendation as to the appropriate fair value rate of return ("FVROR") and to the reasonableness of the Company's proposed fair value rate base ("FVRB"). My analyses and recommendations are supported by the data presented in

[1] Throughout my Direct Testimony, I interchangeably use the terms "ROE" and "Cost of Equity".

Exhibit AEB-1 through Exhibit AEB-12, which were prepared by me or under my direction.

Q. Please provide a brief overview of the analyses that led to your ROE recommendation.

A. As discussed in more detail in Section VI, in developing my ROE recommendation, I applied the Constant Growth and Multi-Stage forms of the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), and the Risk Premium approach. I also considered several additional risk factors that affect the Company's required ROE: (1) the Company's capital expenditure requirements; (2) the Company's small size relative to the proxy group; and (3) the regulatory environment in which the Company operates. Finally, I considered the Company's proposed capital structure as compared to the capital structures of the proxy companies. While I did not make any specific adjustments to my ROE estimates for any of these factors, I did take them into consideration in aggregate when determining where the Company's ROE falls within the range of analytical results.

Q. What are your conclusions regarding the appropriate Cost of Equity for the Company?

A. My analyses indicate that the Company's Cost of Equity should be within the range of 10.00 percent to 10.60 percent. Considering the results of the analyses summarized in Chart 1 and discussed in greater detail in the remainder of my testimony, I believe that a reasonable ROE for UNS Electric is 10.35 percent.

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

A. The remainder of my Direct Testimony is organized as follows: Section III provides a summary of my analyses and conclusions; Section IV reviews the regulatory guidelines pertinent to the development of the cost of capital; Section V discusses current and projected capital market conditions and the effect of those conditions on the Company's Cost of Equity; Section VI explains my selection of a proxy group of electric utilities; Section VII describes my analyses and the analytical basis for the recommendation of the appropriate ROE for UNS Electric; Section VIII provides a discussion of specific regulatory, business, and financial risks that have a direct bearing on the ROE to be authorized for the Company in this case; Section IX discusses the capital structure of the Company as compared with the proxy group; Section X presents my conclusions and recommendation for the market Cost of Equity; Section XI discusses my analysis of the Company's proposed FVRB; and Section XII discusses the estimation of the FVROR.

III. SUMMARY OF ANALYSIS AND CONCLUSIONS

Q. Please summarize the key factors considered in your analyses and upon which you base your recommended ROE.

A. My analyses and recommendations considered the following:

- The *Hope* and *Bluefield* decisions[2] that established the standards for determining a fair and reasonable allowed ROE, including consistency of the allowed return with other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and that the end result must lead to just and reasonable rates.

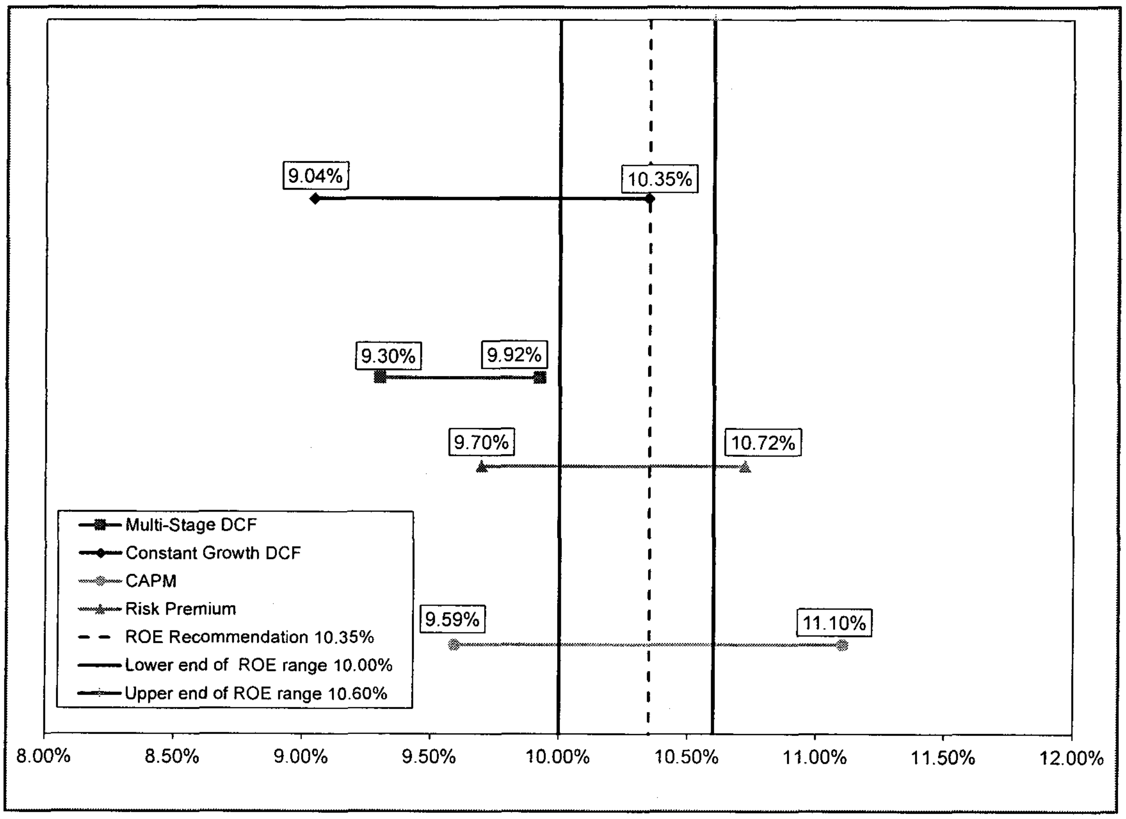
[2] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944); *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923).

- The effect of current and projected capital market conditions on investors' return requirements.
- The Company's regulatory, business, and financial risks relative to the proxy group of comparable companies and the implications of those risks in arriving at the appropriate ROE.

Q. Please summarize the ROE estimation models that you considered to establish the range of ROEs for UNS Electric.

A. I considered the results of two forms of the DCF model: the Constant Growth DCF and the Multi-Stage DCF. In addition, I considered two risk premium approaches: the CAPM and a Bond Yield Plus Risk Premium methodology. Chart 1 summarizes the range of results established using each of these estimation methodologies.

Chart 1: Summary of Cost of Equity Analytical Results



As shown on Chart 1, the range of the DCF model results is very wide, particularly in relation to the results of the other methodologies. While it is common to consider multiple models to estimate the Cost of Equity, it is particularly important when the range of results is wide.

As discussed in more detail in Section VIII, the DCF models are influenced by market conditions that are not projected to be sustained in the long term. Those conditions have a tendency to result in lower estimates of the Return on Equity using the DCF model. As shown in Exhibit AEB-1, the DCF models produce individual company results as low as 4.38 percent, which is below the Company's embedded cost of long-term debt. Furthermore, the mean low Constant Growth DCF results are below an acceptable range of returns for an electric utility and below any authorized ROE for an electric utility company for at least the last 25 years.[3] Therefore, I believe the returns at the low end of the DCF range do not provide a sufficient risk premium to compensate equity investors for the residual risks of ownership, including the risk that they have the lowest claim on the assets and income of the Company. Because of this concern, I have not considered the low end of the range of DCF results in developing my ROE recommendation.

Furthermore, I agree with the position that the Arizona Corporation Commission ("Commission") has previously stated that considering the DCF results alone would not result in an appropriate Cost of Equity under current circumstances.[4] While I have concerns about the results produced by the DCF models, my ROE recommendation is based on the results of the DCF model and a forward-looking CAPM analysis, taking into

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[3] Source: Regulatory Research Associates.
[4] *See* Decision No. 69663 (June 28, 2007), at 49.

consideration the business and company-specific risk factors. The Bond Yield Plus Risk Premium analysis, while not relied on specifically for the ROE recommendation, corroborates the range established for my recommendation.

Q. What is your recommended ROE for UNS Electric?

A. The analytical results presented in Chart 1 provide the range of results for the proxy group companies. I also considered the level of regulatory, business, and financial risk faced by the Company relative to the proxy group in order to establish where UNS Electric's ROE falls within the range. Based on the analytical results in Chart 1, a reasonable range of ROE estimates for UNS Electric is from 10.00 percent to 10.60 percent, and within that range, 10.35 percent is a reasonable and appropriate estimate of the Company's ROE. This recommendation reflects the range of results for the proxy group companies, the relative risk of UNS Electric as compared to the proxy group, and current capital market conditions. The required ROE should be a forward-looking estimate; therefore, the analyses supporting my recommendation rely on forward-looking inputs and assumptions (*e.g.,* projected growth rates in the DCF model, forecasted risk-free rate and Market Risk Premium in the CAPM analysis, etc.) and takes into consideration the current high valuations of utility stocks and the market's expectation for higher interest rates. The use of historical inputs and assumptions would tend to understate the required ROE for UNS Electric, especially under current and projected conditions in capital markets.

Q. Please summarize the analysis that you conducted to validate the FVRB for UNS Electric.

A. Consistent with Commission precedent, the Company has estimated the FVRB by weighting equally its Original Cost Rate Base ("OCRB") and an estimate of the

Replacement Cost New, Depreciated ("RCND") of those assets. I relied on a Comparable Transactions analysis to test the FVRB that is being relied on in the FVROR analysis.

I estimated the market value of UNS Electric's assets by comparing the Company's proposed FVRB to the market value of comparable companies in recent arms-length transactions. To create a consistent basis of comparison among the transactions (which took place amid different market conditions), I normalized the transaction values using the corporate value of the acquired company, which incorporates the book value of debt and equity, resulting in a premium to corporate value resulting from the transactions. I estimated the market value of UNS Electric's assets by applying the median premium of 43.64 percent to the Company's OCRB. That analysis resulted in an estimated market value for UNS Electric's assets of $390.7 million.

Q. What do you conclude from that analysis?

A. Based on the results of the Comparable Transactions analysis, I conclude that the Company's proposed FVRB of $355.7 million is conservative relative to the higher estimate of market value discussed above.

Q. How did you estimate the FVROR?

A. I estimated the FVROR using the approach relied on by the Commission in several recent rate cases. In applying that method, I also conclude that the minimum rate of return that should be applied to the fair value "increment" of rate base is the real risk-free rate of return, which I estimate to be 3.01 percent. Notwithstanding the market expectation that the risk-free rate should represent the floor on investments that are not risk-free, the Company has conservatively proposed the use of 50.0 percent of the risk-free rate in the estimate of the FVROR calculation. As shown in Tables 1 and 2, the result of that analysis is a FVROR of 6.22 percent.

Table 1: Estimation of the FVRB

Capital	$ Millions	Percent	Cost Rate	Weighted Cost Rate
OCRB	**$272.0**	**50%**		**$136.0**
RCND	**$439.4**	**50%**		**$219.7**
FVRB				**$355.7**

Table 2: Estimation of the FVROR

Capital	$ Millions	Percent	Cost Rate	Weighted Cost Rate
Long-Term Debt	**$128.3**	**36.07%**	**4.66%**	**1.68%**
Common Equity	**$143.7**	**40.40%**	**10.35%**	**4.18%**
Fair Value Increment	**$ 83.7**	**23.53%**	**1.50%**	**0.35%**
Total	**$355.7**	**100.00%**		**6.22%**

IV. REGULATORY GUIDELINES

Q. Please describe the guiding principles to be used in establishing the cost of capital for a regulated utility.

A. The United States Supreme Court's precedent-setting *Hope* and *Bluefield* cases established the standards for determining the fairness or reasonableness of a utility's allowed ROE. Among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; (2) adequacy of the return to support credit quality and access to capital; and (3) that the end result, as opposed to the methodology employed, is the controlling factor in arriving at just and reasonable rates.[5]

[5] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944); *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923).

Based on those recognized standards, the return authorized in this case should provide the Company with the opportunity to earn an ROE that is:

- Adequate to attract capital on reasonable terms, thereby enabling the Company to provide safe, reliable service;
- Sufficient to ensure the financial soundness of the Company's operations; and
- Commensurate with returns on investments in comparable risk enterprises.

The allowed ROE should enable the Company to finance capital expenditures on reasonable terms and optimize its financial flexibility over the period during which rates are expected to remain in effect.

Q. Has the Commission provided similar guidance in establishing the appropriate return on common equity?

A. Yes, it has. The Commission has noted that under the Arizona Constitution, a public utility is entitled to a fair return on the fair value of its property devoted to public uses. The Commission is required to find the fair value of the utility's property and to use that value to establish just and reasonable rates.[6]

Q. Why is it important for a utility to be allowed the opportunity to earn an ROE that is adequate to attract capital at reasonable terms?

A. An ROE that is adequate to attract capital at reasonable terms enables the Company to continue to provide safe, reliable electric utility service while maintaining its financial integrity. To the extent the Company has the opportunity to earn its market-based cost of capital, neither customers nor shareholders are disadvantaged.

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[6] *See, e.g., Arizona Corp. Comm'n v. Ariz. Water Co.*, 85 Ariz. 198, 203, 335 P.2d 412, 415 (1959).

Q. What are your conclusions regarding regulatory guidelines and capital market expectations?

A. It is important for the ROE authorized in this proceeding to take into consideration current and projected capital market conditions, as well as investors' expectations and requirements for both risks and returns. Further, in light of the Company's capital investment requirements, it is important that UNS Electric be afforded the opportunity to maintain a financial profile that will enable it to access the capital markets at reasonable rates.

V. CAPITAL MARKET CONDITIONS

Q. What factors are affecting the Cost of Equity for regulated utilities in the current and projected capital markets?

A. The Cost of Equity for regulated utility companies is being affected by several factors in the current and projected capital markets, including: (1) the market's expectation for substantially higher interest rates; (2) current low yields on utility stocks; (3) current high valuations on utility shares relative to historical levels and relative to the broader market; and (4) wider credit spreads between utility bonds and Treasury bonds. In this section, I will discuss each of these factors and how it affects the Cost of Equity for regulated utilities.

Q. Please discuss the current interest rate environment.

A. In October 2014, the Federal Open Market Committee ("FOMC") ended its Quantitative Easing program, which provided extraordinary monetary stimulus for the U.S. economy over the last few years through asset purchases of mortgage-backed securities and

Treasury bonds. In December 2014, the FOMC's policy statement indicated that future changes in short-term interest rates would depend on maintaining a reasonable balance between the level of unemployment and inflation. In February 2015, the FOMC Chair noted that the U.S. unemployment rate has decreased to 5.7 percent since July, job gains increased during the second half of 2014 and continued to increase in January 2015 and long-term unemployment had declined substantially.[7] In addition, real Gross Domestic Product is estimated to have increased at a rate of 3.75 percent, while consumer price inflation remains in check.

Q. What evidence is there that long-term interest rates are expected to increase?

A. While the FOMC did not increase interest rates in January, the Chair noted in her recent speech that the Committee is reasonably confident that inflation will increase over the medium term. In addition to the stated expectations of the FOMC, market analysts are expecting increases in interest rates in the short and medium term. The 30-day average yield on the 30-year U.S. Treasury bond as of February 27, 2015 was 2.50 percent. By contrast, the Blue Chip consensus estimate projects that the average yield on the 30-year U.S. Treasury bond will increase to 4.90 percent for the period from 2016 through 2020.[8] Thus, the consensus estimate from leading economists is for an increase of 240 basis points in U.S. Treasury bond yields over the next several years.

Q. What effect do rising interest rates have on the Cost of Equity for regulated utilities?

A. The market's expectation for rising interest rates suggests that the calculated Cost of Equity for the proxy companies using current market data is likely to be a conservative

[7] Statement by Janet L. Yellen Chair, Board of Governors of the Federal Reserve System before the Committee on Banking, Housing and Urban Affairs, U.S. Senate, February 24, 2015.

[8] Blue Chip Financial Forecasts, Vol. 33, No. 12, December 1, 2014, at 14.

estimate of investors' required return during the period that UNS Electric's rates will be in effect. Consequently, rising interest rates would support selection of a return toward the upper end of a reasonable range of equity cost rate estimates.

Q. What is the financial market's expectation regarding the Federal Reserve's plans to start raising short-term interest rates?

A. The March 2015 issue of Blue Chip Financial Forecasts surveyed market participants concerning their views regarding the timing of possible future rate increases by the Federal Reserve. Blue Chip reports that 100 percent of the 48 market participants surveyed expect that the Federal Reserve will start raising the target for short-term interest rates at some point during 2015, with the most likely date being at either the June 2015 or September 2015 FOMC meeting.[9]

Q. What are your conclusions regarding the effect of higher interest rates for electric utilities such as UNS Electric?

A. Many income-oriented investors hold utility stocks for their dividend yields. During periods in which interest rates are expected to increase, the dividend yields of utility stocks become less attractive for income-oriented investors relative to bond yields, placing pressure on utility share prices relative to the broader market, as measured by the S&P 500 Index. The potential for rising interest rates indicates that the calculated Cost of Equity for the proxy companies using any Cost of Equity estimation technique relying on discounted cash flows is likely to lag investors' required return during the period that UNS Electric's rates will be in effect. Consequently, a consensus expectation of rising interest rates supports selection of a return for UNS Electric based not only on the Multi-Stage DCF model, but also a forward-looking CAPM analysis.

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[9] Blue Chip Financial Forecasts, Volume 34, No. 3, March 1, 2015, at 14.

Q. Please discuss how the period of abnormally low interest rates has affected the valuation and dividend yields of utility shares.

A. The Federal Reserve's Quantitative Easing program resulted in higher asset prices for many common stocks, including shares of public utility companies, as investors sought higher returns and more attractive yields than were being offered by bonds. Consequently, the current share price of many utility stocks has increased to levels above Value Line's target price for the 2017-2019 time period, while the dividend yield of those same utility stocks has declined to unusually low levels. As shown in Chart 2, the average price-to-earnings ("P/E") ratio for the S&P Utility Index in recent months has been well above the long-term average, indicating that investors have been willing to pay more for a dollar of earnings than they were in the past. Higher current P/E ratios also suggest that future returns for this sector will be muted, because current share prices already reflect investors' expectations for future earnings growth.

Chart 2: S&P Utilities Index P/E Ratio

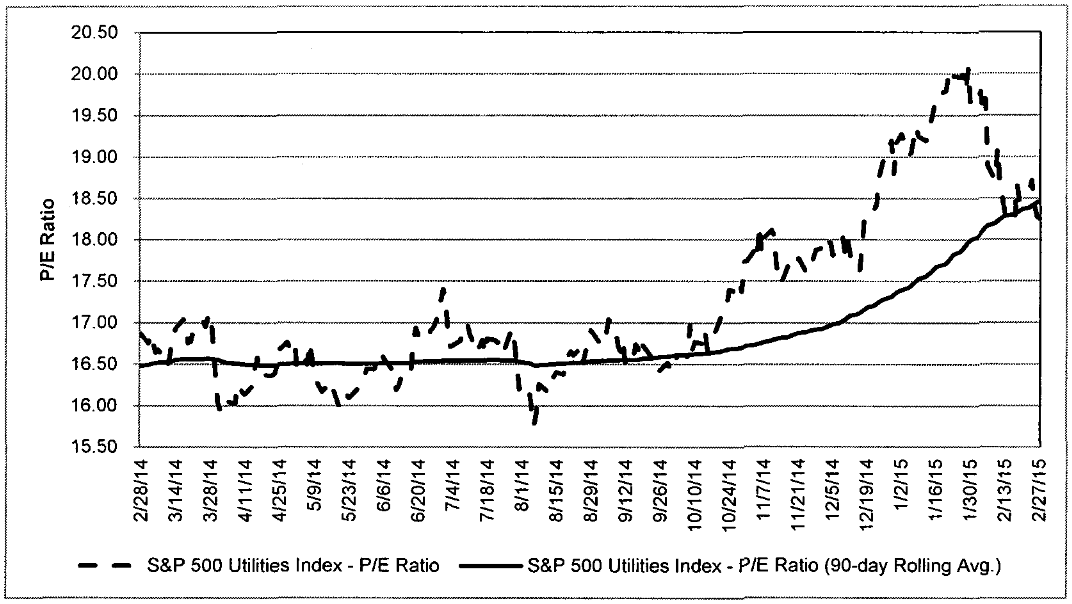
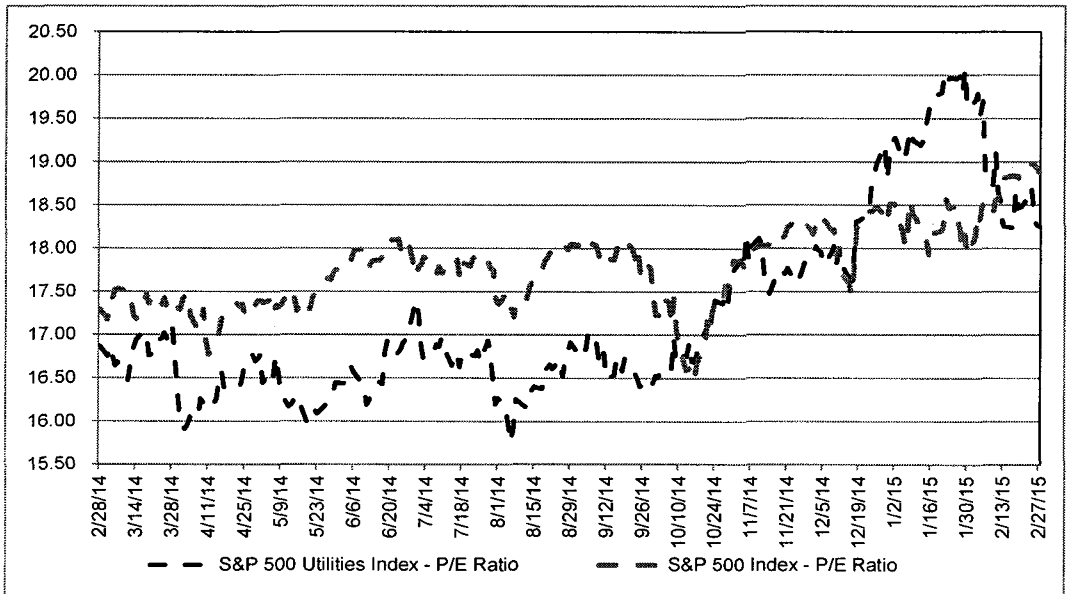
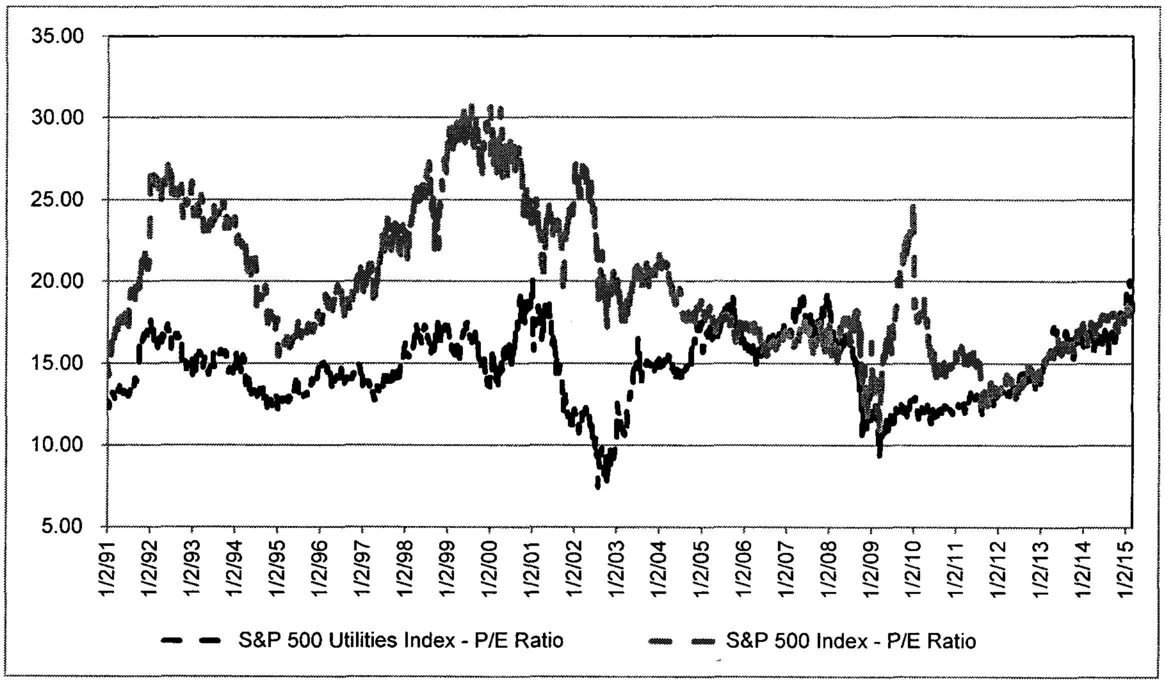


Chart 3: S&P Utilities Index vs. S&P 500 Index P/E Ratio



Similarly, the average P/E ratio for the S&P Utility Index has recently been either higher than or on par with the P/E ratio for the S&P 500. As shown in Chart 4, the opposite was generally true prior to the financial market dislocation. This is further evidence that utility share valuations are high relative to the broader market. It is reasonable to expect those valuations for utility stocks will decline as economic growth accelerates and investors rotate out of the utility sector into more economically-sensitive and growth-oriented sectors.

Chart 4: S&P Utilities Index and S&P 500 Index P/E Ratio - 1991-2015



Further, as discussed in more detail in Section VII, analysts project the valuations of the proxy group stocks to decline in the near term as evidenced by Value Line's projected P/E ratios for that group.

Q. Have you conducted any additional analysis of investor risk sentiment?

A. Yes, I have. Incremental credit spreads are a widely-recognized measure of investor risk sentiment. Wider credit spreads indicate that investors are requiring a higher premium (*i.e.*, a higher interest rate) to compensate them for the higher risk associated with longer-term or lower-rated debt instruments. My analysis compared the average credit spreads between various government and corporate bonds as of February 27, 2015 to the average spreads as of January 10, 2014, which was the date of the Commission's decision in UNS

Electric's previous rate case. As shown on Table 3, the average credit spreads as of February 2015 are generally similar to or higher than those in January 2014.

Table 3: Credit Spreads

Bond Yields	Current Credit Spreads 2/27/15	1/10/2014 UNS Electric 2013 Rate Decision	Great Recession 12/3/2007-6/30/2009
Moody's Baa-Rated - Moody's A Rated Utility Bond	0.70%	0.49%	0.80%
Moody's Baa-rated Utility Bond – 30-year U.S. Treasury	1.78%	1.48%	3.03%
Moody's A-rated Utility Bond – 30-year U.S. Treasury	1.08%	0.99%	2.23%

In particular, the spread between the Moody's Baa-rated utility bond index and the Moody's A-rated utility bond index has increased from 49 basis points to 70 basis points, and is approaching the 80 basis point spread that prevailed during the Great Recession of 2007-2009. Similarly, the spread between the Moody's Baa-rated utility bond index and the 30-year Treasury yield has increased from 148 basis points to 178 basis points, and the spread between the Moody's A-rated utility bond index and the 30-year Treasury yield has increased from 99 basis points to 108 basis points. These wider credit spreads are an indication of higher risk sentiment among utility bond investors, despite lower yields on U.S. Treasury bonds. It is reasonable to reflect higher investor risk sentiment through a higher Cost of Equity.

Q. Why is it important to analyze capital market conditions?

A. It is important to consider the effect of capital market conditions on the inputs and assumptions used in the ROE estimation models and to consider whether or not those market conditions are sustainable over the period that the recommended ROE would be in effect.

A. What conclusions do you draw from your analysis of capital market conditions?

A. Because the utility sector has been trading at a P/E multiple that is considerably higher than the historical range and, in recent periods, higher than the broader market index, it is important to consider whether or not those multiples and relationships will remain constant over time, as is assumed in the DCF model. Furthermore, since interest rates are projected to increase substantially, it is important to reflect that expectation in the specification of the CAPM and other risk premium models.

VI. PROXY GROUP SELECTION

Q. Why have you used a group of proxy companies to estimate the Cost of Equity for UNS Electric?

A. In this proceeding, we are focused on estimating the Cost of Equity for UNS Electric's electric utility operations in Arizona. Since the Cost of Equity is a market-based concept, and given that UNS Electric does not make up the entirety of a publicly traded entity, it is necessary to establish a group of companies that is both publicly traded and comparable to UNS Electric in certain fundamental business and financial respects to serve as its "proxy" in the ROE estimation process.

Even if the Company's electric utility operations in Arizona did constitute the entirety of a publicly-traded entity, it is possible that transitory events could bias its market value over a given period of time. A significant benefit of using a proxy group is that it moderates the effects of unusual events that may be associated with any one company. The proxy companies used in my analyses all possess a set of operating and risk characteristics that are substantially comparable to the Company, and thus provide a reasonable basis to derive and estimate the appropriate ROE for UNS Electric.

Q. **Please provide a brief profile of UNS Electric.**

A. UNS Electric generates, transmits and distributes electricity to approximately 93,000 retail customers in non-contiguous service territories in the Mohave and Santa Cruz counties of Arizona.[10] As of December 31, 2014, UNS Electric represented approximately 10 percent of the assets of UNS Energy and approximately 3 percent of the total assets of ultimate parent company Fortis.[11] UNS Electric currently has an investment grade long-term rating of A3 from Moody's, which was upgraded from Baa1 on March 2, 2015.[12]

Q. **How did you select the companies included in your proxy group?**

A. I began with the group of 46 companies that Value Line classifies as electric utilities and I simultaneously applied the following screening criteria to exclude companies that:

- Do not pay consistent quarterly cash dividends because such companies cannot be analyzed using the Constant Growth DCF model.
- Do not have positive long-term earnings growth forecasts from at least two equity analysts.
- Do not have investment grade long-term issuer ratings from both S&P and Moody's.
- Derive less than 60.0 percent of their total operating income from regulated operations.

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10 Fortis Inc. 2014 Annual Report, page 121.
11 Fortis Inc. 2014 Annual Report, pages 1 and 121.
12 Moody's Investors Service, Credit Opinion UNS Electric, Inc., March 2, 2015.

- Derive less than 90.0 percent of their total regulated operating income from regulated electric operations.
- Were party to a merger or transformative transaction during the analytical period considered.

Q. Did you consider other factors in addition to the screening criteria discussed above?

A. Yes, I did. I also considered whether each company that passed the screening criteria was, in fact, generally comparable to UNS Electric in terms of business and financial risk. On that basis, I excluded one additional company: Edison International.

On November 1, 2012, Edison International announced that Edison Mission Electric (EME), its competitive power generation segment, would not be able to repay $500 million in bonds that were to mature in June 2013. In December 2012, EME filed for bankruptcy protection under Chapter 11 of the U.S. bankruptcy code. In March 2014, the court approved the plan of reorganization for EME; however, payments to creditors will continue through 2016.[13] Due to the ongoing bankruptcy proceeding of EME, it is not reasonable to include Edison International in the proxy group at this time.

Q. What is the composition of your proxy group?

A. My proxy group consists of the companies shown in Table 4.

[13] United States Bankruptcy Court, Northern District of Illinois, Eastern Division, Case No. 12-49219 (JPC), decision entered February 19, 2014, at 2. *See also* Edison International 2014 SEC Form 10-K, p. 9.

Table 4: Proxy Group

Company	Ticker
ALLETE, Inc.	ALE
American Electric Power Company, Inc.	AEP
Duke Energy Corporation	DUK
Empire District Electric Company	EDE
Eversource Energy	ES
Great Plains Energy Inc.	GXP
IDACORP, Inc.	IDA
Otter Tail Corporation	OTTR
Pinnacle West Capital Corporation	PNW
PNM Resources, Inc.	PNM
Portland General Electric Company	POR
Southern Company	SO
Westar Energy, Inc.	WR

VII. COST OF EQUITY ESTIMATION

Q. Please briefly discuss the ROE in the context of the regulated rate of return.

A. The overall rate of return for a regulated utility is based on its weighted average cost of capital, in which the cost rates of the individual sources of capital are weighted by their respective book values. While the costs of debt and preferred stock can be directly observed, the Cost of Equity is market-based and, therefore, must be estimated based on observable market data.

Q. How is the required ROE determined?

A. The required ROE is estimated by using one or more analytical techniques that rely on market-based data to quantify investor expectations regarding required equity returns, adjusted for certain incremental costs and risks. Informed judgment is then applied to determine where the Company's Cost of Equity falls within the range of results. The key consideration in determining the Cost of Equity is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets in general, as well as the subject company (in the context of the proxy group) in particular.

Q. What methods did you use to determine the Company's ROE?

A. I considered the results of the DCF models and the CAPM analysis, corroborated by the Bond Yield Plus Risk Premium methodology. As discussed in more detail below, a reasonable ROE estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results.

Q. Why is it important to use more than one analytical approach?

A. It is important to use more than one approach because the Cost of Equity is not directly observable, and therefore must be estimated based on both quantitative and qualitative information. When faced with the task of estimating the Cost of Equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed. A number of models have been developed to estimate the Cost of Equity. Analysts and academics understand that ROE models are tools to be used in the ROE estimation process and that strict adherence to any single approach, or the specific results of any single approach, can lead to flawed conclusions. Consistent with the *Hope* finding, it is the analytical result, not the methodology, that is controlling in arriving at ROE determinations. A reasonable ROE estimate, therefore, considers alternative methodologies, observable market data, and the reasonableness of their individual and collective results.

A. Constant Growth DCF Model

Q. Are DCF models widely used to estimate the ROE for regulated utilities?

A. Yes. DCF models are widely used in regulatory proceedings and have sound theoretical bases, although neither the DCF model nor any other model can be applied without considerable judgment in the selection of data and the interpretation of results. As discussed later in this section of my testimony, the currently high P/E ratios for utility companies, and the expectation that the P/E ratios of the proxy companies will decline in the near term raises concerns with the use of the DCF approach as the sole indicator of the Cost of Equity at this time.

Q. Please describe the DCF approach.

A. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_\infty}{(1+k)^\infty} \quad [1]$$

Where P_0 represents the current stock price, $D_1 \ldots D_\infty$ are all expected future dividends, and k is the discount rate, or required ROE. Equation [1] is a standard present value calculation that can be simplified and rearranged into the following form:

$$k = \frac{D_0(1+g)}{P_0} + g \quad [2]$$

Equation [2] is often referred to as the Constant Growth DCF model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

Q. What assumptions are required for the Constant Growth DCF model?

A. The Constant Growth DCF model requires the following assumptions: (1) a constant growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings ratio; and (4) a discount rate greater than the expected growth rate. To the extent that any of these assumptions is violated, considered judgment and/or specific adjustments should be applied to the results.

Q. What market data did you use to calculate the dividend yield in your Constant Growth DCF model?

A. The dividend yield in my Constant Growth DCF model is based on the proxy companies' current annualized dividend and average closing stock prices over the 30-, 90-, and 180-trading days ended February 27, 2015.

Q. Why did you use 30-, 90-, and 180-day averaging periods?

A. It is important to use an average of recent trading days to calculate the term P_0 in the DCF model to ensure that the ROE is not skewed by anomalous events that may affect stock prices on any given trading day. The averaging period should also be reasonably representative of expected capital market conditions over the long-term. In my view, the use of the 30-, 90-, and 180-day averaging periods reasonably balances those considerations.

Q. Did you make any adjustments to the dividend yield to account for periodic growth in dividends?

A. Yes, I did. Since utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half of the expected annual dividend growth rate for purposes of calculating the expected dividend yield component of the DCF model. This adjustment ensures that the expected first year dividend yield is, on average, representative of the coming twelve-month period, and does not overstate the aggregated dividends to be paid during that time.

Q. Why is it important to select appropriate measures of long-term growth in applying the DCF model?

A. In its Constant Growth form, the DCF model (*i.e.*, Equation [2]) assumes a single growth estimate in perpetuity. In order to reduce the long-term growth rate to a single measure, one must assume a constant payout ratio, and that earnings per share, dividends per share and book value per share all grow at the same constant rate. Over the long run, however, dividend growth can only be sustained by earnings growth. It, therefore, is important to incorporate a variety of sources of long-term earnings growth rates into the Constant Growth DCF model.

Q. Which sources of long-term earnings growth rates did you use?

A. My Constant Growth DCF model incorporates three sources of long-term earnings growth rates: (1) Zacks Investment Research; (2) Thomson First Call (provided by Yahoo! Finance); and (3) Value Line Investment Survey.

B. Multi-Stage DCF Model

Q. What other forms of the DCF model did you consider?

A. In order to address some of the limiting assumptions underlying the Constant Growth form of the DCF model, I also considered the results of a Multi-Stage DCF model. As with the Constant Growth form, the Multi-Stage DCF model defines the Cost of Equity as the discount rate that sets the current price equal to the discounted value of future cash flows.

Q. What are the benefits of a three-stage model?

A. The Multi-Stage model, which is an extension of the Constant Growth form, enables the analyst to specify growth rates over multiple stages. Further, the three-stage model allows for a gradual transition from the first stage growth rate to the long-term growth rate, thereby avoiding the often-unrealistic assumption that growth will change abruptly between the first and final stages.

Q. Please generally describe the structure of your Multi-Stage DCF model.

A. The Multi-Stage DCF model sets the subject company's current stock price equal to the present value of future cash flows received over three "stages". In all three stages, cash flows are equal to the annual dividend payments that stockholders receive. Stage one is a short-term growth period that consists of the first five years; stage two is a transition period from the short-term growth rate to the long-term growth rate which occurs over five years (*i.e.*, years six through 10); and stage three is a long-term growth period that begins in year 11 and continues in perpetuity (*i.e.*, year 200). The ROE is then calculated as the rate of return that results from the initial stock investment and the dividend payments over the analytical period.

Q. Please summarize the earnings per share growth rates used in your Multi-Stage DCF model.

A. I began with the current annualized dividend as of February 27, 2015 for each proxy group company. In the first stage of the model, the current annualized dividend is escalated based on the average of the three- to five-year earnings growth estimates reported by First Call, Zacks, and Value Line. For the third stage of the model, I relied on long-term projected growth in Gross Domestic Product ("GDP"). The second stage growth rate is a transition from the first stage growth rate to the long-term growth rate on a geometric average basis.

Q. How did you calculate the long-term GDP growth rate?

A. As shown on Exhibit AEB-3, the long-term growth rate of 5.51 percent is based on the real GDP growth rate of 3.26 percent from 1929 through 2014,[14] and a projected inflation rate of 2.19 percent. The rate of inflation of 2.19 percent is an average based on three measures: (1) the average long-term projected growth rate in the Consumer Price Index ("CPI") of 2.30 percent;[15] (2) the compound annual growth rate of the CPI for all urban consumers for 2025-2040 of 2.26 percent as projected by the Energy Information Administration ("EIA"); and (3) the compound annual growth rate of the GDP chain-type price index for 2025-2040 of 2.00 percent, also reported by the EIA.[16]

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[14] U.S. Department of Commerce, Bureau of Economic Analysis, National Income and Product Accounts Tables, Table 1.1.1, February 27, 2015.

[15] Blue Chip Financial Forecasts, Vol. 33, No. 12, December 1, 2014, at 14.

[16] U.S. Energy Information Administration, Annual Energy Outlook 2014, Table 20, Macroeconomic Indicators.

Q. Why did you use a historical GDP growth rate rather than a current estimate of GDP growth?

A. Based on current and recent market conditions, the use of a historical growth rate is more appropriate than using a current estimate of real GDP growth. Economists have reviewed historical growth patterns related to severe financial crises and have concluded that estimates of GDP growth have generally been understated in the decade following severe financial crises. Specifically, the financial crisis and recession that began in 2007 were qualitatively different from most other U.S. economic downturns, which were followed by a rapid return to pre-recession overall output growth levels. In that regard, the current U.S. economic growth situation is similar to that following the two most severe economic events in U.S. history (*i.e.*, the 1929 stock market crash and the 1973 oil shock). Economists that have examined the repercussions of those two historical crises (and similar severe financial crises in other countries) have found that GDP growth rates tended to be lower during the decade following such events.[17] Therefore, it would not be appropriate to assume that current projections of GDP growth are representative of long-term GDP growth starting in 2025 and continuing for the next 200 years.

Q. Have you performed an analysis to determine whether real GDP growth is slower in the decade immediately after a severe financial crisis than in subsequent decades?

A. Yes. I compared the average real GDP growth in the first ten years immediately following the two historical economic crises most comparable to the recent financial crisis (*i.e.*, the 1929 stock market crash and the 1973 oil shock) to the average real GDP growth in the next two decades following each crisis (*i.e.*, eleven to 30 years after the

[17] *See,* Reinhart, Carmen M. and Vincent R. Reinhart, "After the Fall," NBER Working Paper 16334, September 2010, in Federal Reserve Bank of Kansas City Economic Policy Symposium Volume, *Macroeconomic Challenges: The Decade Ahead* at Jackson Hole, Wyoming, on August 26-28, 2010, at 2.

events). I did the same for each of the 20th-century U.S. recessions for which sufficient data are available. My findings are presented in Table 5.

Table 5: Real GDP Growth Rates Following U.S. Economic Downturns[18]

Event	Compound Average Real GDP Growth Rate		
	Decade Following Crisis	Next Two Decades	Difference (Basis Points)
Major Economic Crises			
1929 Stock Market Crash	2.06%	4.72%	266
1973 Oil Shock	2.55%	3.39%	83
Other Recessions			
1937	6.68%	4.15%	-253
1945	3.77%	3.59%	-18
1948	3.79%	3.95%	16
1953	3.60%	3.23%	-37
1957	4.84%	3.13%	-170
1960	4.41%	3.28%	-112
1969	3.57%	3.01%	-56
1980	3.32%	2.45%	-88
1981	3.52%	2.62%	-90

Table 5 shows that real GDP growth in the first ten years following the 1929 stock market crash and the 1973 oil shock was substantially lower than real GDP growth in the next two decades following each event. In contrast, eight out of the nine other 20th-century U.S. economic downturns analyzed showed the opposite pattern. In light of the academic research cited above and the findings presented in Table 5, it is reasonable to believe that current projections of real GDP growth are under-stated. For that reason, the most reasonable means to forecast long-term GDP growth is to assume a return to long-term historical rates of real GDP growth and to estimate long-term nominal GDP growth based largely on market-based, long-term inflation estimates.

18 Real GDP data are from the U.S. Bureau of Economic Analysis. The years in which each recession started are from the National Bureau of Economic Research ("NBER"), "US Business Cycle Expansions and Contractions," available at http://www.nber.org/cycles.html. Note that this table excludes the three most recent recessions, which started in 1990, 2001, and 2007 owing to a lack of sufficient data for GDP growth in the following years to calculate comparable long-term GDP growth rates.

C. Discounted Cash Flow Model Results

Q. Please summarize the results of your DCF analyses.

A. Table 6 (*see* also Exhibit AEB-1 and Exhibit AEB-2) presents the results of the Constant Growth and Multi-Stage DCF models. The Constant Growth DCF model produces a range of mean results from 8.19 percent to 10.35 percent. The Multi-Stage DCF analysis produces a range of mean results from 9.08 percent to 9.92 percent.

Table 6: Discounted Cash Flow Results

Constant Growth DCF			
	Mean Low	**Mean**	**Mean High**
30-Day Average Price	8.19%	9.04%	10.05%
90-Day Average Price	8.28%	9.14%	10.14%
180-Day Average Price	8.49%	9.34%	10.35%
Multi-Stage DCF			
	Mean Low	**Mean**	**Mean High**
30-Day Average Price	9.08%	9.30%	9.58%
90-Day Average Price	9.18%	9.40%	9.69%
180-Day Average Price	9.39%	9.63%	9.92%

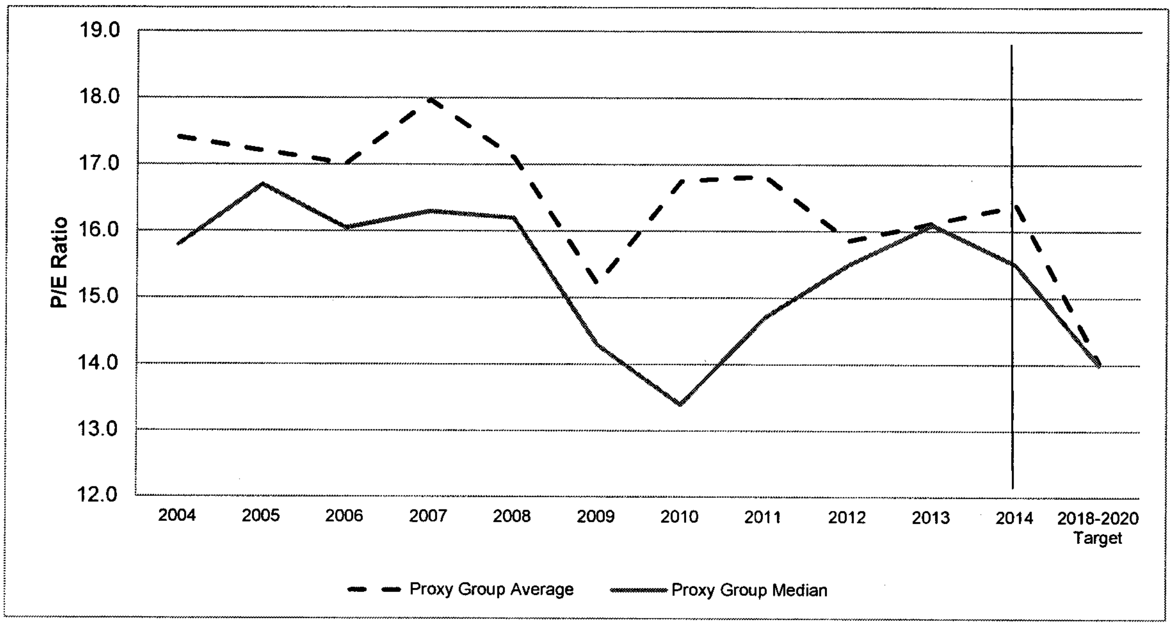
Q. How did you calculate the range of results for the Constant Growth and Multi-Stage DCF Models?

A. I calculated the low result for both DCF models using the minimum growth rate (*i.e.*, the lowest of the First Call, Zacks, and Value Line earnings growth rates) for each of the proxy group companies. Thus, the low result reflects the minimum DCF result for the proxy group. I used a similar approach to calculate the high results, using the highest growth rate for each proxy group company. The mean results were calculated using the average growth rates from all three sources.

Q. How do you explain the low results from the DCF models?

A. In its commentary on the electric utility industry, Value Line observes that many of the companies are currently trading at prices near their three-to-five year price targets.[19] Value Line cautions investors that current valuations already reflect the projected earnings growth for these companies, and that investors should look elsewhere for better return potential. These high valuations help explain why the results of the Constant Growth DCF analysis are currently so low. As shown in Chart 5, below, the average P/E ratio for the proxy companies was higher at the end of 2014 than the average projected P/E ratio for the group for the period from 2018-2020. The expectation for lower P/E ratios for the proxy companies suggests that the current results from the DCF model should be considered with caution.

Chart 5: Average Historical P/E Ratios for Proxy Companies



[19] Value Line Investment Survey, Electric Utility (West) Industry, January 31, 2015.

Q. Does the Multi-Stage DCF model discussed above address your concern about utility valuations?

A. No, it does not. While the Multi-Stage DCF model provides for changes in growth over time, it does not address the very high P/E ratios for utility stocks and the effects of those high valuations on the dividend yield in the DCF model.

Q. What are your conclusions about the results of the DCF models?

A. I agree with the position that Commission has previously stated (*i.e.,* that considering the DCF results alone would not result in an appropriate Cost of Equity under current circumstances).[20] As discussed previously, one primary assumption of the DCF models is for a constant P/E ratio. That assumption is heavily influenced by the market price of utility stocks. To the extent that these stock prices are inflated, as is suggested by the high P/E ratios and the expectation by analysts that those P/E ratios are not sustainable in the short term, it is important to consider the results of the DCF models with caution. Therefore, while I have considered the range of results established using the DCF methodologies, my recommendation also gives some weight to the results of the CAPM and also considers the indications from the Bond Yield Plus Risk Premium analysis.

Q. Are you aware of any decisions wherein a Regulatory agency that determines the Cost of Equity has considered the effectiveness of the traditional ROE estimation models?

A. Yes, I am. The Surface Transportation Board ("STB"), which regulates the U.S. railroad industry, began evaluating the effectiveness of the Constant Growth DCF model in September 2006. The STB instituted a broad rulemaking to obtain public comment on

[20] *See* Decision No. 69663 (June 28, 2007), at 49.

the most appropriate methodology to use for estimating the ROE for railroads. In January 2008, the STB replaced the Constant Growth DCF model with the CAPM, with the expectation that the CAPM would produce more accurate estimates of the industry's cost of capital. In January 2009, as a result of its exploration of the various forms of ROE estimation models and the review of public comments on the merits and shortcomings of each of the models, the STB issued a decision modifying its sole reliance on the CAPM method to include an equal weighting of the CAPM and the Multi-Stage DCF results. In reaching this decision, the STB concluded that:

> Indeed, if our exploration of this issue has revealed nothing else, it has shown that there is no single simple or correct way to estimate the cost of equity for the railroad industry, and countless reasonable options are available. Both the CAPM and the multi-stage DCF models we propose to use have strengths and weaknesses, and both take different paths to estimate the same illusory figure. By using an average of the results produced by both models, we harness the strengths of both models while minimizing their respective weaknesses.[21]

This decision supports my view that it is appropriate to consider the results of various financial models to estimate the Cost of Equity within the context of capital market conditions, and that the models that are most appropriate to be used to estimate the ROE may evolve over time as market conditions change.

Q. Is it relevant that the STB does not regulate the energy industry?

A. No. The STB decision is an ROE decision, and therefore it is relevant regardless of the industry. That decision describes the rigorous analysis and the methodologies that a

[21] Surface Transportation Board, Use of a Multi-Stage Discounted Cash Flow Model in Determining the Railroad Industry's Cost of Capital, Decision STB Ex Parte No. 664 (Sub-No. 1), released January 28, 2009, at 15.

regulatory body used to review financial models and to select the most appropriate models in the context of capital market conditions in order to estimate the Cost of Equity.

In summary, as the STB decision points out, the models used to estimate the ROE are used by the investment community for all types of investments, and therefore it is not important that the STB does not regulate energy companies. Rather, what is important is that the methodologies used reflect what investors consider in establishing their return requirements.

D. CAPM Analysis

Q. Please briefly describe the Capital Asset Pricing Model.

A. The CAPM is a risk premium approach that estimates the Cost of Equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable or "systematic" risk of that security. This second component is the product of the market risk premium and the Beta coefficient, which measures the relative riskiness of the security being evaluated.

The CAPM is defined by four components, each of which must theoretically be a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f) \quad [3]$$

Where:

K_e = the required market ROE;

β = Beta coefficient of an individual security;

r_f = the risk-free rate of return; and

r_m = the required return on the market as a whole.

In this specification, the term $(r_m - r_f)$ represents the market risk premium. According to the theory underlying the CAPM, since unsystematic risk can be diversified away, investors should only be concerned with systematic or non-diversifiable risk. Non-diversifiable risk is measured by Beta, which is defined as:

$$\beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)} \quad [4]$$

The variance of the market return (*i.e.*, *Variance* (r_m)) is a measure of the uncertainty of the general market, and the covariance between the return on a specific security and the general market (*i.e.*, *Covariance* (r_e, r_m)) reflects the extent to which the return on that security will respond to a given change in the general market return. Thus, Beta represents the risk of the security relative to the general market.

Q. What risk-free rate did you use in your CAPM analysis?

A. I relied on three sources for my estimate of the risk-free rate: (1) the current 30-day average yield on 30-year U.S. Treasury bonds (*i.e.*, 2.50 percent);[22] (2) the projected 30-year U.S. Treasury bond yield for 2015 through 2016 of 3.20 percent;[23] and (3) the projected 30-year U.S. Treasury bond yield for 2016 through 2020 of 4.90 percent.[24]

Q. Why did you consider both the current average yield on 30-year Treasury bonds and the projected near-term and longer-term Treasury bond yields?

A. The inputs and assumptions used in the CAPM analysis should reflect the forward-looking cost of equity. As discussed in Section V of my Direct Testimony, leading

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[22] Bloomberg Professional, as of February 27, 2015.
[23] Blue Chip Financial Forecasts, Vol. 34, No. 2, February 1, 2015, at 2.
[24] Blue Chip Financial Forecasts, Vol. 33, No. 12, December 1, 2014, at 14.

economists surveyed by Blue Chip are expecting a substantial increase in long-term interest rates over the next five years. This is an important consideration for equity investors as they assess their return requirements. A CAPM analysis based entirely on the current average risk-free rate of 2.50 percent fails to take into consideration the effect of the market's expectations for interest rate increases on the Cost of Equity. For that reason, I have used projected yields on the 30-year Treasury security as the risk free rate because those yields reflect investor expectations with respect to inflation during the period in which rates will be in effect.

Q. What Beta coefficients did you use in your CAPM analysis?

A. As shown on Exhibit AEB-4, I used the average Beta coefficients for the proxy group companies as reported by Bloomberg and Value Line. Bloomberg calculates Beta coefficients based on two years of weekly returns relative to the S&P 500 Index. Value Line's calculation is based on five years of weekly returns relative to the New York Stock Exchange Composite Index.

Q. How did you estimate the market risk premium in the CAPM?

A. I estimated the market risk premium based on the expected return on S&P 500 Index less the 30-year Treasury bond yield. The expected return on the S&P 500 Index is calculated using the Constant Growth DCF model discussed earlier in my Direct Testimony for the companies in the S&P 500 Index for which dividend yields and long-term earnings projections are available. Based on an estimated market capitalization-weighted dividend yield of 2.00 percent and a weighted long-term growth rate of 11.06 percent, the estimated required market return for the S&P 500 Index is 13.17 percent. The implied market risk premium over the current 30-day average of the 30-year U.S. Treasury bond yield, and the short- and near-term projected yields on the 30-year U.S. Treasury bond, range from 8.27 percent to 10.67 percent.

Q. Why is a forward-looking market risk premium more appropriate than a historical market risk premium?

A. The historical market risk premium fails to consider the inverse relationship between interest rates and the market risk premium. As shown in my Bond Yield plus Risk Premium analysis, as interest rates decrease, the market risk premium increases. The historical market risk premium reported by Morningstar is based on an income only return on government bonds of 5.10 percent (which is significantly higher than the current yield on government bonds) subtracted from the long-term return on large company stocks of 12.10 percent.[25] Therefore, the historical market risk premium is under-stated relative to current or near-term projected interest rates, which are well below the long-term average yield of 5.10 percent. As such, it is more appropriate to use a forward-looking market risk premium that reflects projected total returns for the S&P 500 less the current and projected yield on Treasury securities.

Q. What are the results of your CAPM analyses?

A. As shown in Table 7 (*see* also Exhibit AEB-5), my CAPM analysis produces a range of returns from 9.59 percent to 11.10 percent. The mean return using the Bloomberg average Beta coefficient and three measure of the risk-free rate is 9.94 percent. Using the Value Line average Beta coefficient and three measures of the risk-free rate, the mean result is 10.76 percent.

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[25] Morningstar, Inc., Ibbotson SBBI 2014 Classic Yearbook, at Table 6-7.

Table 7: Forward-Looking CAPM Results

	Current Risk-Free Rate (2.50%)	2015-2016 Projected Risk-Free Rate (3.20%)	2016-2020 Projected Risk-Free Rate (4.90%)	Mean Result
Bloomberg Beta	9.59%	9.83%	10.40%	9.94%
Value Line Beta	10.50%	10.68%	11.10%	10.76%

E. Bond Yield Plus Risk Premium Analysis

Q. Please describe the Bond Yield Plus Risk Premium approach you employed.

A. In general terms, this approach is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned as a bondholder. That is, since returns to equity holders are more risky than returns to bondholders, equity investors must be compensated to bear that risk. Risk premium approaches, therefore, estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. In my analysis, I used actual authorized returns for electric utilities as the historical measure of the Cost of Equity to determine the risk premium.

Q. Are there other considerations that should be addressed in conducting this analysis?

A. Yes. It is important to recognize both academic literature and market evidence indicating that the equity risk premium (as used in this approach) is inversely related to the level of interest rates. That is, as interest rates increase (decrease), the equity risk premium decreases (increases). Consequently, it is important to develop an analysis that: (1) reflects the inverse relationship between interest rates and the equity risk premium; and (2) relies on recent and expected market conditions. Such an analysis can be developed based on a regression of the risk premium as a function of U.S. Treasury bond yields. If we let authorized ROEs for electric utilities serve as the measure of required equity returns and define the yield on the long-term U.S. Treasury bond as the relevant measure of interest rates, the risk premium simply would be the difference between those two points.[26]

Q. Is the Bond Yield Plus Risk Premium analysis relevant to investors?

A. Yes. Investors are aware of ROE awards in other jurisdictions, and they consider those awards as a benchmark for a reasonable level of equity returns for utilities of comparable risk operating in other jurisdictions. Since my Bond Yield Plus Risk Premium analysis is based on authorized ROEs for electric utilities relative to corresponding Treasury yields, it provides relevant information to assess the return expectations of investors. However, I have relied on this analysis to corroborate the reasonableness of my DCF and CAPM results and to inform my ultimate ROE recommendation, not as the primary basis for my recommendation.

Q. What did your Bond Yield Plus Risk Premium analysis reveal?

A. As shown on Chart 6, from 1992 through February 2015, there was a strong negative relationship between risk premia and interest rates. To estimate that relationship, I conducted a regression analysis using the following equation:

$$RP = a + b(T) \quad [5]$$

Where:

RP = Risk Premium (difference between allowed ROEs and the yield on 30-year U.S. Treasury bonds)

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[26] *See e.g.*, S. Keith Berry, *Interest Rate Risk and Utility Risk Premia during 1982-93*, Managerial and Decision Economics, Vol. 19, No. 2 (March, 1998), in which the author used a methodology similar to the regression approach described below, including using allowed ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates. *See also* Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholders Required Rates of Return*, Financial Management, Spring 1986, at 66.

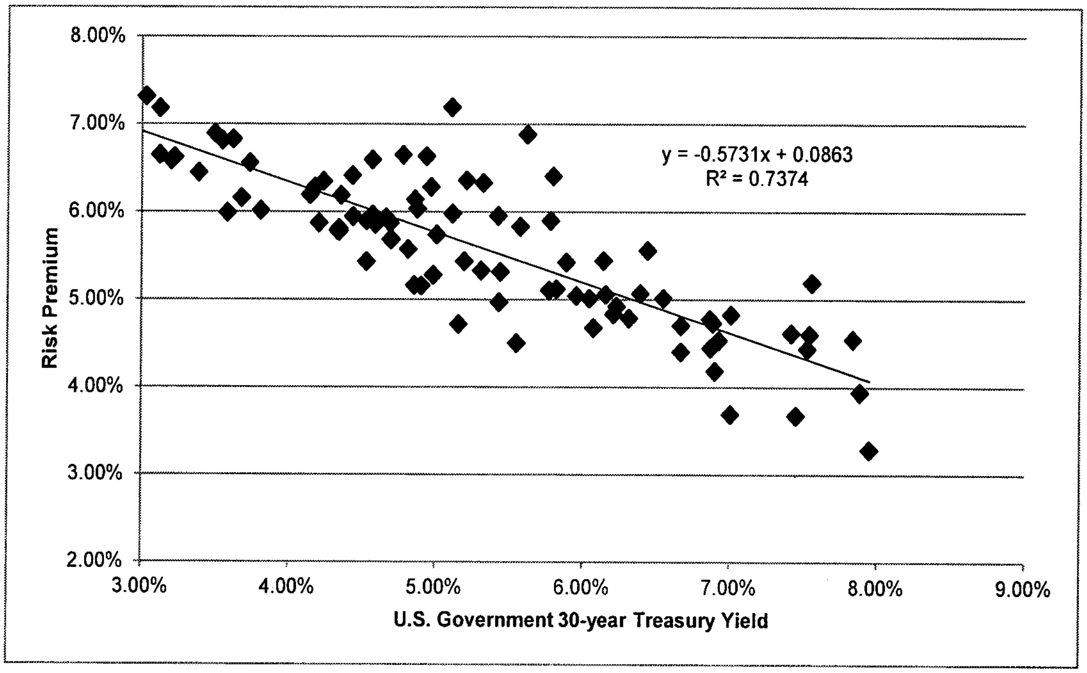
a = intercept term

b = slope term

T = 30-year U.S. Treasury bond yield

Data regarding allowed ROEs were derived from 633 rate cases from 1992 through February 2015 as reported by Regulatory Research Associates. This equation's coefficients were statistically significant at the 99.0 percent level.

Chart 6: Risk Premium Results



As shown on Exhibit AEB-6, based on the current 30-day average of the 30-year U.S. Treasury bond yield (*i.e.*, 2.50 percent), the risk premium would be 7.20 percent, resulting in an estimated ROE of 9.70 percent. Based on the near-term (2015-2016) projections of the 30-year U.S. Treasury bond yield (*i.e.*, 3.20 percent), the risk premium would be 6.80 percent, resulting in an estimated ROE of 10.00 percent. Based on longer-term (2016-2020) projections of the 30-year U.S. Treasury bond yield (*i.e.*, 4.90 percent), the risk premium would be 5.82 percent, resulting in an estimated ROE of 10.72 percent.

VIII. REGULATORY AND BUSINESS RISKS

Q. Do the mean DCF, CAPM, and Risk Premium results for the proxy group provide an appropriate estimate of the cost of equity for UNS Electric?

A. No. These results provide only a range of the appropriate estimate of the Company's Cost of Equity. There are several additional factors that must be taken into consideration when determining where the Company's Cost of Equity falls within the range of results. These factors, which are discussed below, should be considered with respect to their overall effect on the Company's risk profile.

A. UNS Electric's Capital Expenditure Plan

Q. Please summarize the Company's capital expenditure requirements.

A. The Company's current projections include approximately $189 million in capital investments for the period from 2015 through 2019.[27] As discussed in the Direct Testimony of Company witness Terry Nay, the Company's capital expenditure plan includes approximately $14 million for generation system improvements, $91.4 million for transmission and distribution improvements, $26.1 million for new customer demands, and $27.5 million for renewable energy projects. Based on the Company's net utility plant as of December 31, 2013 of approximately $328.2 million,[28] the $189.0 million anticipated capital expenditures represents 57.6 percent of UNS Electric's net utility plant as of December 31, 2013.

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27 Company projection of capital spending as of December 2014

28 UNS Electric, Inc., FERC Form 1 for the year ended December 31, 2013, at 110.

Q. How is the Company's risk profile affected by its substantial capital expenditure requirements?

A. As with any utility faced with substantial capital expenditure requirements, the Company's risk profile may be adversely affected in two significant and related ways: (1) the heightened level of investment increases the risk of under recovery or delayed recovery of the invested capital; and (2) an inadequate return would put downward pressure on key credit metrics.

Q. Do credit rating agencies recognize the risks associated with elevated levels of capital expenditures?

A. Yes, they do. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. To that point, a July 2014 report from S&P explains:

> [T]here is little doubt that the U.S. electric industry needs to make record capital expenditures to comply with the proposed carbon pollution rules over the next several years, while maintaining safety standards and grid stability. We believe the higher capital spending and subsequent rise in debt levels could strain these companies' financial measures, resulting in an almost consistent negative discretionary cash flow throughout this higher construction period. To meet the higher capital spending requirements, companies will require ongoing and steady access to the capital markets, necessitating that the industry maintains its high credit quality. We expect that utilities will continue to effectively manage their regulatory risk by using various creative means to recover their costs and to finance their necessary higher spending.[29]

Therefore, to the extent that UNS Electric's rates do not permit it to recover its full cost of doing business, the Company will face increased recovery risk and thus increased pressure on its credit metrics.

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[29] Standard and Poor's, Ratings Direct, "U.S. Regulated Electric Utilities' Annual Capital Spending Is Poised to Eclipse $100 Billion," July 2014.

Q. **UNS Electric has a cost recovery mechanism that enables the Company to reduce its regulatory lag for transmission costs. How does this cost recovery mechanism affect UNS Electric's risk profile, and its resulting Cost of Equity?**

A. The ROE recommendation is established for a company based on its risk relative to the proxy group. As such, it is necessary to consider how cost recovery mechanisms such as UNS Electric's Transmission Cost Adjustor ("TCA") affect the Company's risk profile relative to the proxy companies. I have reviewed the cost recovery mechanisms that have been implemented by each of the proxy companies. As shown in Exhibit AEB-7, 62 percent of the proxy group companies have risk-mitigating capital recovery mechanisms similar to the TCA. Since the majority of proxy group companies have implemented capital tracking mechanisms, the TCA does not make UNS Electric unique. My conclusion is that it is not necessary to adjust the authorized ROE for UNS Electric on that basis.

Q. **What are your conclusions regarding the effect of the Company's capital spending requirements on its risk profile and cost of capital?**

A. It is clear that the Company's capital expenditure requirements as a percentage of net utility plant will remain relatively high over the next few years. As such, the risk posed by these elevated capital expenditure requirements indicates that UNS Electric should be afforded the opportunity to earn an ROE at the upper end of the reasonable range of ROEs.

B. Small Size Risk

Q. Please explain the risk associated with small size.

A. Both the financial and academic communities have long accepted the proposition that the Cost of Equity for small firms is subject to a "size effect". While empirical evidence of the size effect often is based on studies of industries other than regulated utilities, utility analysts also have noted the risk associated with small market capitalizations. Specifically, an analyst for Ibbotson Associates noted:

> For small utilities, investors face additional obstacles, such as a smaller customer base, limited financial resources, and a lack of diversification across customers, energy sources, and geography. These obstacles imply a higher investor return.[30]

Q. How does the smaller size of a utility affect its business risk?

A. In general, smaller companies are less able to withstand adverse events that affect their revenues and expenses. The impact of weather variability, the loss of large customers to bypass opportunities, or the destruction of demand as a result of general macroeconomic conditions or fuel price volatility will have a proportionately greater impact on the earnings and cash flow volatility of smaller utilities. Similarly, capital expenditures for non-revenue producing investments, such as system maintenance and replacements, will put proportionately greater pressure on customer costs, potentially leading to customer attrition or demand reduction. Taken together, these risks affect the return required by investors for smaller companies.

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[30] Michael Annin, *Equity and the Small-Stock Effect*, Public Utilities Fortnightly, October 15, 1995.

Q. How does UNS Electric's electric utility operations compare in size to the proxy group companies?

A. UNS Electric's electric utility operations are substantially smaller than the median for the proxy group companies in terms of market capitalization. Exhibit AEB-8 provides the actual market capitalization for the proxy group companies and estimates the implied market capitalization for UNS Electric (*i.e.*, the implied market capitalization if UNS Electric's electric utility operations were a stand-alone publicly-traded entity). To estimate the size of the Company's market capitalization relative to the proxy group, I used the Company's proposed capital structure equity component of $189.9 million. I then applied the median market-to-book ratio for the proxy group of 1.66 to UNS Electric's implied common equity balance and arrived at an implied market capitalization of approximately $315.1 million, or 7.19 percent of the median market capitalization for the proxy group.

Q. How did you estimate the size premium for UNS Electric?

A. Given this relative size information, it is possible to estimate the impact of size on the ROE for UNS Electric using Morningstar data that estimates the stock risk premia based on the size of a company's market capitalization.[31] As shown in Exhibit AEB-8, the median market capitalization of the proxy group of approximately $4.38 billion corresponds to the fourth decile of the Morningstar market capitalization data.[32] Based on Morningstar's analysis, that decile corresponds to a size premium of 1.19 percent (*i.e.*, 119 basis points). UNS Electric's implied market capitalization of approximately $315.1 million falls within the tenth decile, which comprises market capitalization levels up to $338.8 million and corresponds to a size premium of 6.01 percent (*i.e.*, 601 basis points).

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31 Morningstar, Inc., Ibbotson SBBI 2014 Classic Yearbook, at Table 7-6.

32 Morningstar, Inc., Ibbotson SBBI 2014 Classic Yearbook, at Table 7-5.

The difference between those size premia is 482 basis points (*i.e.*, 6.01 percent minus 1.19 percent).

Q. Have you considered the smaller size of UNS Electric in your recommended ROE?

A. While I have estimated the small size effect, I am not proposing a specific adjustment for this factor. Rather, I have considered the small size of UNS Electric in my assessment of business risks in order to determine where, within a reasonable range of returns, UNS Electric's required ROE falls.

C. UNS Electric's Regulatory Environment

Q. Please explain how the regulatory environment affects investors' risk assessments.

A. The ratemaking process is premised on the principle that, in order for investors and companies to commit the capital needed to provide safe and reliable utility service, the subject utility must have the opportunity to recover the return of, and the market-required return on, invested capital. Regulatory commissions recognize that because utility operations are capital intensive, regulatory decisions should enable the utility to attract capital at reasonable terms; doing so balances the long-term interests of investors and customers. UNS Electric is no exception. It must finance its operations and requires the opportunity to earn a reasonable return on its invested capital in order to maintain its financial profile. In that respect, the regulatory environment is one of the most important factors considered in both debt and equity investors' risk assessments.

From the perspective of debt investors, the authorized return should enable the Company to generate the cash flow needed to meet its near-term financial obligations, make the capital investments needed to maintain and expand its system, and maintain sufficient levels of liquidity to fund unexpected events. This financial liquidity must be derived not only from internally generated funds, but also by efficient access to capital markets. Moreover, because fixed income investors have many investment alternatives, even within a given market sector, the Company's financial profile must be adequate on a relative basis to ensure its ability to attract capital under a variety of economic and financial market conditions.

From the perspective of equity investors, the authorized return must be adequate to provide a risk-comparable return on the equity portion of the Company's capital investments. Because equity investors are the residual claimants on the Company's cash flows (which is to say that the equity return is subordinate to interest payments), they are particularly concerned with the strength of regulatory support and its effect on future cash flows.

Q. Please explain how credit rating agencies consider regulatory risk in establishing a company's credit rating.

A. While both S&P and Moody's consider regulatory risk in establishing credit ratings, Moody's has published a report quantifying the importance of this metric. Moody's establishes credit ratings based on four key factors: (1) regulatory framework; (2) the ability to recover costs and earn returns; (3) diversification; and (4) financial strength, liquidity, and key financial metrics. Of these criteria, regulatory framework and the ability to recover costs and earn returns are each given a broad rating factor of 25.0 percent. Therefore, Moody's assigns regulatory risk a 50.0 percent weighting in the overall assessment of business and financial risk for regulated utilities.[33]

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[33] Moody's Investors Service, *Rating Methodology: Regulated Electric and Gas Utilities*, December 23, 2013, at 6.

S&P has also identified regulatory risk as an important factor. In its assessment of U.S. utility regulatory environments, S&P stated, "we believe the fundamental regulatory environment in the jurisdictions in which a utility operates often influences credit quality the most."[34]

Q. How does the regulatory environment in which a utility operates affect its access to and cost of capital?

A. The regulatory environment can significantly affect both the access to, and cost of capital in several ways. First, the proportion and cost of debt capital available to utility companies are influenced by the rating agencies' assessment of the regulatory environment. As noted by Moody's, "For rate regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations"[35] Moody's further highlighted the relevance of a stable and predictable regulatory environment to a utility's credit quality, noting: "Broadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation."[36]

Q. Have you conducted any analysis of the regulatory environment in Arizona relative to the jurisdictions in which the companies in your proxy group operate?

A. Yes. S&P classifies each regulatory jurisdiction into five categories ranging from "Strong" to "Weak" based on the level of credit supportiveness. Within each category, regulatory jurisdictions are ranked according to their credit supportiveness from most credit supportive to least credit supportive. For my analysis of the credit supportiveness

34 Standard & Poor's, *Assessing U.S. Utility Regulatory Environments*, March 11, 2010, at 2.
35 Moody's Investors Service, *Rating Methodology: Regulated Electric and Gas Utilities*, December 23, 2013, at 9.
36 *Ibid.*

of the regulatory jurisdictions in which the proxy companies operate, I assigned a numerical ranking to each jurisdiction ranked by S&P, from most credit supportive ("1") to least credit supportive ("53"). As shown in Exhibit AEB-9, the proxy group average ranking was 24.48, which would be classified as Strong/Adequate and rank slightly above average for credit supportiveness, while the Arizona jurisdictional ranking was 30, which is somewhat below average in credit supportiveness.

Q. What are your conclusions regarding the perceived risks related to the Arizona regulatory environment?

A. As discussed throughout this section of my testimony, both Moody's and S&P have identified the supportiveness of the regulatory environment as an important consideration in developing their overall credit ratings for regulated utilities. The S&P credit supportiveness ranking for Arizona indicates somewhat greater risk than the average for the proxy companies. For that reason, I conclude that it would be reasonable to consider a Cost of Equity toward the upper end of the range established by the proxy group.

IX. CAPITAL STRUCTURE

Q. What is UNS Electric's proposed capital structure?

A. As described in the Direct Testimony of Mr. Grant, the Company's proposed capital structure consists of 52.83 percent common equity and 47.17 percent long-term debt, based on the test year actual capital structure for the period ending December 31, 2014.

Q. Please discuss your analysis of the capital structures of the proxy group companies.

A. My analysis of the proxy group companies' actual capital structures is provided in Exhibit AEB-10. As shown in that exhibit, I calculated the mean proportions of common equity and long-term debt over the most recent eight quarters[37] for each of the proxy group companies at the operating company level. The Company's proposed equity ratio of 52.83 percent is slightly below the mean of the proxy group of 53.72 percent and well within the range of mean common equity ratios for the proxy group companies of 48.04 percent to 63.05 percent.

Q. What is your conclusion regarding an appropriate capital structure for UNS Electric?

A. Considering the actual capital structures of the proxy group's operating companies, I believe that UNS Electric's proposed common equity ratio of 52.83 percent is reasonable.

X. CONCLUSIONS AND RECOMMENDATION

Q. What is your conclusion regarding a fair ROE for UNS Electric?

A. Based on the various quantitative and qualitative analyses presented in my Direct Testimony, and in light of the business and financial risks of UNS Electric compared to the proxy group, it is my view that an ROE of 10.35 percent is fair and reasonable and would balance the interests of customers and shareholders. Specifically, my ROE recommendation would enable the Company to maintain its financial integrity and therefore its ability to attract capital at reasonable rates under a variety of economic and

[37] Source: SNL Financial and FERC Form 1 quarterly reports.

financial market conditions, while continuing to provide safe, reliable and affordable electric utility service to customers in Arizona.

Table 8: Summary of Analytical Results

Constant Growth DCF			
	Mean Low	**Mean**	**Mean High**
30-Day Average Price	8.19%	9.04%	10.05%
90-Day Average Price	8.28%	9.14%	10.14%
180-Day Average Price	8.49%	9.34%	10.35%
Multi-Stage DCF			
	Mean Low	**Mean**	**Mean High**
30-Day Average Price	9.08%	9.30%	9.58%
90-Day Average Price	9.18%	9.40%	9.69%
180-Day Average Price	9.39%	9.63%	9.92%
Capital Asset Pricing Model			
	Current Risk-Free Rate (2.50%)	**2015-2016 Projected Risk-Free Rate (3.20%)**	**2016-2020 Projected Risk-Free Rate (4.90%)**
Bloomberg Beta	9.59%	9.83%	10.40%
Value Line Beta	10.50%	10.68%	11.10%
Bond Yield Plus Risk Premium			
	Current Risk-Free Rate (2.50%)	**2015-2016 Projected Risk-Free Rate (3.20%)**	**2016-2020 Projected Risk-Free Rate (4.90%)**
Bond Yield Plus Risk Premium	9.70%	10.00%	10.72%
Size Premium	4.82%		

Q. What is your conclusion with respect to UNS Electric's proposed capital structure?

A. My conclusion is that the Company's proposed capital structure consisting of 52.83 percent common equity and 47.17 percent long-term debt is reasonable compared to the mean capital structures for the proxy group companies.

XI. FAIR VALUE RATE BASE

Q. What is the fair value standard in Arizona?

A. As the Commission noted in its decision regarding *Chaparral City Water Company*,[38] the Arizona Constitution requires the use of a fair value rate base in establishing rates. Article XV, Section 14 of the Arizona Constitution states:

> The corporation commission shall, to aid it in the proper discharge of its duties, ascertain the fair value of the property within the state of every public service corporation doing business therein; and every public service corporation doing business within the state shall furnish to the commission all evidence in its possession, and all assistance in its power, requested by the commission in aid of the determination of the value of the property within the state of such public service corporation.[39]

As interpreted by the Arizona Court of Appeals, this paragraph requires the Commission to find the fair value of a public service corporation's property and to use that value to set just and reasonable rates.[40]

Q. How has the Commission applied the fair value standard in prior cases?

A. The fair value standard, as applied by the Commission in recent rate cases, includes the estimation of two components: (1) the FVRB; and (2) the FVROR on the FVRB.[41]

Q. How has the Commission estimated the FVRB?

A. In several recent cases, the Commission has determined that it was appropriate to estimate the FVRB by weighting equally the OCRB and the RCND. The RCND

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38 Decision No. 70441 (July 28, 2008), at 20-21.
39 Arizona Constitution, Article XV, Section 14.
40 Decision No. 70441 (July 28, 2008), at 20-21.
41 Decision No. 71914 (September 30, 2010), at 51.

estimates the current replacement cost value of the utility system by escalating the utility's original investments in rate base assets by inflation, since the installation year of the asset. In order to recognize physical and functional depreciation of the assets, the replacement cost is then adjusted for the accounting depreciation of the assets based on the expected useful life of the asset, as determined through the company's depreciation study.

Q. How do you define "fair value"?

A. Used in the regulatory context of determining a just and reasonable rate of return, "fair value" is the price at which a property would change hands between a willing buyer and a willing seller, when neither party is under any compulsion to enter into a transaction, and when both parties have reasonable knowledge of relevant facts.[42] That definition is consistent with the Internal Revenue Code and Revenue Ruling 59-60 ("Ruling 59-60"), which notes that court decisions regarding fair value further assume that the buyer and seller are "able, as well as willing, to trade and to be well informed about the property and concerning the market for such property."[43]

Q. Do you have any concerns with the methodology that the Commission has used to estimate the FVRB?

A. Yes, I do. Applying a 50.0 percent weight to the OCRB to estimate the FVRB is inconsistent with valuation theory that is relied upon by investors. Valuation theory identifies three traditional approaches that are used to estimate the value of an asset: (1) the Income Approach; (2) the Cost Approach; and (3) the Comparable Transactions Approach. The Income Approach establishes the value of the asset based on the present discounted value of the expected income from the asset. Using the Cost Approach, an

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[42] *See* Shannon P. Pratt, Valuing a Business, 5th ed. McGraw Hill, 2008, at 41-42

[43] IRS Revenue Ruling 59-60, 1959-1 CB 237-IRC Sec. 2031.

investor estimates the value of the asset based on the current cost of a reasonably comparable replacement asset, adjusted to reflect all forms of depreciation that are present in the subject asset. Finally, using the Comparable Transactions or Market Multiples Approach the investor relies on the use of market data on the sale of comparable assets to estimate the value of the assets.

While different circumstances of the asset or the investor can affect whether or not all three approaches are considered or how much emphasis should be placed on any given approach, the objective of each approach is to use available market data to derive a market-based value of an asset. An approach which places a 50.0 percent weight on the depreciated original cost of the assets at the time those assets were installed suggests that the accounting value of an investment has a relationship to the current market value of the asset. This is not the case, as is recognized both in the market place and in academia.[44]

Q. Have you conducted any analysis to assess the reasonableness of using the RCND as the FVRB for UNS Electric?

A. Yes, I have. As noted above, there are three main approaches to valuation typically relied upon by investors and analysts: (1) the Income Approach; (2) the Cost Approach; and (3) the Comparable Transactions Approach. The Income Approach is not appropriate in circumstances such as this where the value of the assets is used to determine the income

[44] *See* Pratt, Reilly, Schweihs, Valuing a Business, 4th ed. Irwin, 2000, at 308, which states: Under any standard of value, the true economic value of a business enterprise equals the company's accounting book value only by coincidence. More likely than not, the true economic value of a company will be either higher or lower than its accounting book value. There is no theoretical support, conceptual reasoning, or empirical data to suggest that the value of a business enterprise (under any standard of value) will necessarily equal the company's accounting book value. From a valuation perspective, the terms *book value* or *net book value* are merely accounting jargon. This is because book value is not related to economic value, or to the valuation process, at all...In any event, accounting book value is not a recommended business valuation method.

of the assets. The RCND is the Company's estimate of the current value of the assets using the Cost Approach. As shown in Exhibit AEB-11, page 1, the FVRB of $355.7 million is calculated by weighting equally the Company's OCRB of $ 272.0 million and the Company's estimated RCND of $ 439.4 million.

In order to determine the reasonableness of the Company's proposed FVRB, which includes a 50.0 percent weight on original cost rate base, I relied on the Comparable Transactions Approach to estimate the market value of the Company's OCRB.

Q. Please explain how you applied the Comparable Transactions Approach to determine the reasonableness of the Company's FVRB.

A. I compared the Company's FVRB estimate to the market value of comparable companies in recent arms-length transactions. I normalized the transaction values using the percentage premium over the corporate value of the acquired company. This metric incorporates the book value of debt and equity to estimate a premium to corporate value resulting from the transactions to create a consistent basis of comparison among the transactions (which took place amid different market conditions). I then estimated the market value of UNS Electric's assets by applying the median premium of 43.64 percent to the Company's OCRB. That analysis resulted in an estimated market value for UNS Electric's assets of $ 390.7 million.

Q. How did you establish the universe of transactions that were analyzed for comparability to the UNS Electric system?

A. I began by developing a database of announced and executed transactions involving the sale of electric and diversified utility companies and assets. Those data were compiled using the SNL Financial utility merger-screening tool. I also reviewed publicly-available information such as press releases, investor presentations, SEC filings, and regulatory commission filings. Once that preliminary list of transactions was developed, I then applied the following screening criteria to establish a final group of transactions for which I calculated the transaction premium.

1. I included transactions that involved the sale of state-regulated investor-owned electric and diversified utilities;
2. I included transactions that resulted in the sale of the entire company, excluding partial system or asset sales; and
3. I included transactions with a value of between $100 million and $10 billion.

There were 43 transactions that met my screening criteria.

Q. What period of time did you consider in developing your list of comparable transactions?

A. My Comparable Transactions analysis was performed on utility transmission and distribution asset transactions that were announced between January 1, 1997 and February 28, 2015. In my view, that period is sufficiently long to avoid the bias that could result from limiting the analysis to a shorter period, yet produces a sufficient number of observations.

Q. Please summarize the result of that analysis.

A. Table 9 summarizes the range of acquisition premiums for the comparable transactions. As shown in Table 9 and in Exhibit AEB-12, the median acquisition premium was 43.64 percent. Applying that premium to UNS Electric's OCRB of $ 272.0 million indicates an implied market value for UNS Electric's assets of $ 390.7 million.

Table 9: Comparable Transaction Multiples

	Transaction Premium	Implied Valuation ($M)
Minimum	-1.75%	$267.3
Maximum	116.90%	$590.0
Mean	47.22%	$400.4
Median	**43.64%**	**$390.7**
Standard Deviation	29.15%	$79.3

Q. Did you include the acquisition of UNS Energy by Fortis Inc. in your analysis?

A. Yes, I included the acquisition of UNS Energy by Fortis in the comparable transactions analysis. As discussed previously, my analysis included 43 transactions and relied on the median premium from those transactions. I did not rely on a valuation of UNS Electric based only on the transaction premium resulting from the UNS Energy acquisition by Fortis, Inc.

Q. What do you conclude from the Comparable Transactions Approach discussed above?

A. The results of the Comparable Transactions Approach demonstrate that the Company's proposed FVRB is conservative relative to the estimated fair market value of the Company's assets.

XII. FAIR VALUE RATE OF RETURN

Q. Does the fair value standard also require consideration of the fair return on the fair value of the Company's assets?

A. Yes. As noted above, the Arizona Constitution requires that the Commission establish just and reasonable rates using the fair value of the Company's property. In establishing the revenue requirement, the Commission would also need to establish the appropriate ROE to apply to the equity component of the FVRB.

Q. How has the Commission estimated the FVROR on the FVRB?

A. In several recent cases, the Commission has determined the FVROR by applying the market ROE and the cost of debt to the Company's OCRB based on the percent of equity and debt in the Company's proposed capital structure. The Commission then applies a different rate, traditionally one half of the risk-free rate, to what has been commonly referred to as the "fair value increment."[45] The fair value increment is the difference between the OCRB and the Company's proposed FVRB. The FVROR is then the sum of the returns on each of the three components: (1) equity capital, (2) debt capital, and (3) the fair value increment, weighted by the percentage of each in the FVRB.

Q. What does the fair value increment represent?

A. As described in the Commission's Decision No. 70665, the fair value increment represents the appreciation in the value of the assets to their current value from the value at which they entered service. Therefore, the sum of the OCRB and the fair value increment is meant to represent the total fair value of the utility's property.[46]

Q. What rate of return should be applied to the fair value increment?

A. Based on the risk differential between equity and debt investments, equity holders will require a greater return than the risk-free rate. As such, the range of returns on the fair value increment should be between the risk-free rate and the Cost of Equity established

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45 Decision No. 70665 (December 24, 2008), at 32.
46 *Ibid.*

by the results of the proxy group analysis. By contrast, there is no basis whatsoever for reducing this return component to one-half of the risk-free rate.

Q. How does your recommended range compare with the range of returns considered in prior cases?

A. In UNS Electric's last rate case, Staff recommended applying a return to the fair value increment ranging between zero and the real risk-free rate.[47]

Q. Do you agree with this methodology of determining the rate of return to be applied to the fair value increment?

A. No, I do not. Since equity investors are the residual claimants after bondholders and preferred stockholders, it is inconceivable to me that an investor would accept a rate of return that is less than the cost of debt for an equity position in any investment. At the very least, the market expectation is that investments that are not risk-free should earn a rate of return that exceeds the risk-free rate. Furthermore, the application of 50.0 percent of the risk-free rate as a measure of the Cost of Equity on the fair value increment is subjective and has no basis in financial theory. The risk-free rate, which was used by the staff to establish the range of returns applied to the fair value increment, sets the low-end of the range of returns that I believe would be appropriate to apply to the fair value increment.

[47] Docket No. E-04204A-12-0504, Direct Testimony of David C. Parcell at 53-55.

Q. How have you estimated the FVROR in this case?

A. While I do not agree with all aspects of the Commission's approach, as shown on page 1 of Exhibit AEB-11, I have estimated the FVROR using the methodology the Commission has approved in recent cases.

Q. How did you estimate the risk-free rate of return?

A. As shown on page 2 of Exhibit AEB-11, my estimate of the nominal risk-free rate of return is the average of the 2016-2020 projected yield on 30-year U.S. Treasury bonds of 4.90 percent and the 2021-2025 projected yield on 30-year U.S. Treasury bonds of 5.10 percent as reported in the Blue Chip Financial Forecasts.[48] I then adjusted the nominal risk-free rate of 5.00 percent by the rate of inflation, which I estimated to be 1.94 percent over the period from 2014-2025 (*see*, Exhibit AEB-11). The resulting real risk-free rate is then 3.01 percent.[49]

Q. Please explain how you estimated the rate of inflation.

A. The rate of inflation of 1.94 percent is based on three measures: (1) the average 2016-2020 and 2021-2025 projected growth rate in the CPI of 2.35 percent, as reported by Blue Chip Financial Forecasts;[50] (2) the compound annual growth rate of the CPI for all urban consumers for 2014-2025 of 1.85 percent as projected by the EIA in the Annual Energy Outlook 2014; and (3) the compound annual growth rate of the GDP chain-type price index for 2014-2025 of 1.61 percent, also reported by the EIA in the Annual Energy Outlook 2014.[51]

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48 Blue Chip Financial Forecasts, Vol. 33, No. 12, December 1, 2014, at 14.

49 $3.01\% = (5.10\% + 1) / (1 + 1.94\%) - 1$.

50 Blue Chip Financial Forecasts, Vol. 33, No. 12, December 1, 2014, at 14.

51 U.S. Energy Information Administration, Annual Energy Outlook 2014, Table 20, Macroeconomic Indicators.

Q. How does this rate of inflation differ from the inflation rate used in your calculation of the long-term growth rate for the Multi-Stage DCF model?

A. While both rates of inflation depend on identical sources, the rate of inflation used to calculate the FVROR is based on the near-term (*i.e.*, 2014-2025) because the company is entitled to earn a return on its FVRB immediately and throughout the period in which rates will be in effect. The third stage of the Multi-Stage DCF model, on the other hand, does not begin until 10 years from now and continues into perpetuity so the long-term GDP growth rate is based on long-term inflation forecasts (*i.e.*, 2025-2040).

Q. Please explain how you applied the Commission's methodology to estimate the FVROR.

A. As shown on page 1 of Exhibit AEB-11 and in Tables 10 and 11 below, I calculated the difference between the Company's OCRB and the Company's proposed FVRB, which includes a 50.0 percent weight on original cost. That difference represents the appreciation in the value of the assets based on the "market value" of the OCRB, and has been commonly referred to as the "fair value increment."[52] The weighted average cost of debt and the market Cost of Equity were applied to the OCRB.

Q. Please explain how you estimated the rate of return that you applied to the fair value increment.

A. As discussed above, I believe that the appropriate range of returns that could be applied to the fair value increment ranges from the low-end measured by the risk-free rate to the high-end measured by the results of the returns on rate base for the proxy group discussed in Section VI of my Direct Testimony. Nevertheless, the Company has requested that I

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52 Decision No. 70665 (December 24, 2008), at 32.

estimate the FVROR by applying 50.0 percent of the risk-free rate or approximately 1.50 percent, to the fair value increment.

Table 10: Estimation of the FVRB

Capital	$ Millions	Percent	Cost Rate	Weighted Cost Rate
OCRB	**$272.0**	**50%**		**$136.0**
RCND	**$439.4**	**50%**		**$219.7**
FVRB	**$355.7**			**$355.7**

Table 11: Estimation of the FVROR

Capital	$ Millions	Percent	Cost Rate	Weighted Cost Rate
Long-Term Debt	**$128.3**	**36.07%**	**4.66%**	**1.68%**
Common Equity	**$143.7**	**40.40%**	**10.35%**	**4.18%**
Fair Value Increment	**$ 83.7**	**23.53%**	**1.50%**	**0.35%**
Total	**$355.7**	**100.00%**		**6.22%**

Q. What is the resulting FVROR?

A. As shown in Tables 10 and 11 (*see also*, Exhibit AEB-11) based on the calculation discussed previously, the FVROR that would be applied to the FVRB is 6.22 percent.

Q. Does this conclude your pre-filed Direct Testimony?

A. Yes, it does.

Exhibit AEB-1

30-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Earnings Growth	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	$2.02	$56.26	3.59%	3.70%	6.00%	6.00%	N/A	6.00%	9.70%	9.70%	9.70%
American Electric Power Company, Inc.	AEP	$2.12	$60.95	3.48%	3.56%	4.50%	5.05%	4.80%	4.78%	8.06%	8.34%	8.62%
Duke Energy Corporation	DUK	$3.18	$84.07	3.78%	3.87%	5.00%	4.41%	4.70%	4.70%	8.28%	8.57%	8.88%
Empire District Electric Company	EDE	$1.04	$28.31	3.67%	3.73%	4.00%	3.00%	3.00%	3.33%	6.73%	7.07%	7.75%
Eversource Energy	ES	$1.67	$54.19	3.08%	3.19%	8.00%	6.25%	6.40%	6.88%	9.43%	10.07%	11.20%
Great Plains Energy Inc.	GXP	$0.98	$28.41	3.45%	3.54%	6.00%	4.60%	4.80%	5.13%	8.13%	8.67%	9.55%
IDACORP, Inc.	IDA	$1.88	$65.84	2.86%	2.90%	1.50%	3.00%	4.00%	2.83%	4.38%	5.73%	6.91%
Otter Tail Corporation	OTTR	$1.23	$31.79	3.87%	4.08%	15.50%	6.00%	N/A	10.75%	9.99%	14.83%	19.67%
Pinnacle West Capital Corporation	PNW	$2.38	$68.58	3.47%	3.54%	4.00%	4.20%	4.00%	4.07%	7.54%	7.61%	7.74%
PNM Resources, Inc.	PNM	$0.80	$29.59	2.70%	2.84%	11.00%	9.86%	8.90%	9.92%	11.72%	12.76%	13.85%
Portland General Electric Company	POR	$1.12	$38.62	2.90%	2.98%	5.00%	5.26%	5.90%	5.39%	7.97%	8.36%	8.89%
Southern Company	SO	$2.10	$49.06	4.28%	4.36%	4.00%	3.40%	3.60%	3.67%	7.75%	8.03%	8.37%
Westar Energy, Inc.	WR	$1.40	$41.50	3.37%	3.45%	6.00%	3.37%	3.80%	4.39%	6.80%	7.84%	9.47%
MEAN				**3.42%**	**3.52%**	**6.19%**	**4.95%**	**4.90%**	**5.53%**	**8.19%**	**9.04%**	**10.05%**

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of February 27, 2015
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

90-DAY CONSTANT GROWTH DCF

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Earnings Growth	[6] Yahoo! Finance Earnings Growth	[7] Zacks Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.02	$53.86	3.75%	3.86%	6.00%	6.00%	N/A	6.00%	9.86%	9.86%	9.86%
American Electric Power Company, Inc.	AEP	$2.12	$59.41	3.57%	3.65%	4.50%	5.05%	4.80%	4.78%	8.15%	8.44%	8.71%
Duke Energy Corporation	DUK	$3.18	$82.74	3.84%	3.93%	5.00%	4.41%	4.70%	4.70%	8.34%	8.64%	8.94%
Empire District Electric Company	EDE	$1.04	$28.44	3.66%	3.72%	4.00%	3.00%	3.00%	3.33%	6.71%	7.05%	7.73%
Eversource Energy	ES	$1.67	$52.20	3.20%	3.31%	8.00%	6.25%	6.40%	6.88%	9.55%	10.19%	11.33%
Great Plains Energy Inc.	GXP	$0.98	$27.53	3.56%	3.65%	6.00%	4.60%	4.80%	5.13%	8.24%	8.78%	9.67%
IDACORP, Inc.	IDA	$1.88	$64.19	2.93%	2.97%	1.50%	3.00%	4.00%	2.83%	4.45%	5.80%	6.99%
Otter Tail Corporation	OTTR	$1.23	$30.69	4.01%	4.22%	15.50%	6.00%	N/A	10.75%	10.13%	14.97%	19.82%
Pinnacle West Capital Corporation	PNW	$2.38	$65.83	3.62%	3.69%	4.00%	4.20%	4.00%	4.07%	7.69%	7.76%	7.89%
PNM Resources, Inc.	PNM	$0.80	$29.24	2.74%	2.87%	11.00%	9.86%	8.90%	9.92%	11.76%	12.79%	13.89%
Portland General Electric Company	POR	$1.12	$37.65	2.98%	3.06%	5.00%	5.26%	5.90%	5.39%	8.05%	8.44%	8.96%
Southern Company	SO	$2.10	$48.38	4.34%	4.42%	4.00%	3.40%	3.60%	3.67%	7.81%	8.09%	8.43%
Westar Energy, Inc.	WR	$1.40	$40.06	3.49%	3.57%	6.00%	3.37%	3.80%	4.39%	6.92%	7.96%	9.60%
MEAN				**3.51%**	**3.61%**	**6.19%**	**4.95%**	**4.90%**	**5.53%**	**8.28%**	**9.14%**	**10.14%**

Notes:
[1] Source: *Bloomberg Professional*
[2] Source: Bloomberg Professional, equals 90-day average as of February 27, 2015
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

180-DAY CONSTANT GROWTH DCF

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Earnings Growth	[6] Yahoo! Finance Earnings Growth	[7] Zacks Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.02	$50.95	3.96%	4.08%	6.00%	6.00%	N/A	6.00%	10.08%	10.08%	10.08%
American Electric Power Company, Inc.	AEP	$2.12	$56.29	3.77%	3.86%	4.50%	5.05%	4.80%	4.78%	8.35%	8.64%	8.91%
Duke Energy Corporation	DUK	$3.18	$78.08	4.07%	4.17%	5.00%	4.41%	4.70%	4.70%	8.57%	8.87%	9.17%
Empire District Electric Company	EDE	$1.04	$26.74	3.89%	3.95%	4.00%	3.00%	3.00%	3.33%	6.95%	7.29%	7.97%
Eversource Energy	ES	$1.67	$48.78	3.42%	3.54%	8.00%	6.25%	6.40%	6.88%	9.78%	10.42%	11.56%
Great Plains Energy Inc.	GXP	$0.98	$26.45	3.71%	3.80%	6.00%	4.60%	4.80%	5.13%	8.39%	8.93%	9.82%
IDACORP, Inc.	IDA	$1.88	$59.74	3.15%	3.19%	1.50%	3.00%	4.00%	2.83%	4.67%	6.02%	7.21%
Otter Tail Corporation	OTTR	$1.23	$29.53	4.17%	4.39%	15.50%	6.00%	N/A	10.75%	10.29%	15.14%	19.99%
Pinnacle West Capital Corporation	PNW	$2.38	$60.83	3.91%	3.99%	4.00%	4.20%	4.00%	4.07%	7.99%	8.06%	8.19%
PNM Resources, Inc.	PNM	$0.80	$28.01	2.86%	3.00%	11.00%	9.86%	8.90%	9.92%	11.88%	12.92%	14.01%
Portland General Electric Company	POR	$1.12	$35.46	3.16%	3.24%	5.00%	5.26%	5.90%	5.39%	8.24%	8.63%	9.15%
Southern Company	SO	$2.10	$46.28	4.54%	4.62%	4.00%	3.40%	3.60%	3.67%	8.02%	8.29%	8.63%
Westar Energy, Inc.	WR	$1.40	$38.09	3.68%	3.76%	6.00%	3.37%	3.80%	4.39%	7.11%	8.15%	9.79%
MEAN				**3.71%**	**3.82%**	**6.19%**	**4.95%**	**4.90%**	**5.53%**	**8.49%**	**9.34%**	**10.35%**

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-day average as of February 27, 2015
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

Exhibit AEB-2

30-DAY MULTI-STAGE DCF -- AVERAGE FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$56.26	$2.02	6.00%	5.92%	5.84%	5.76%	5.68%	5.60%	5.51%	9.59%
American Electric Power Company, Inc.	AEP	$60.95	$2.12	4.78%	4.91%	5.03%	5.15%	5.27%	5.39%	5.51%	9.16%
Duke Energy Corporation	DUK	$84.07	$3.18	4.70%	4.84%	4.97%	5.11%	5.24%	5.38%	5.51%	9.47%
Empire District Electric Company	EDE	$28.31	$1.04	3.33%	3.70%	4.06%	4.42%	4.79%	5.15%	5.51%	9.02%
Eversource Energy	ES	$54.19	$1.67	6.88%	6.66%	6.43%	6.20%	5.97%	5.74%	5.51%	9.21%
Great Plains Energy Inc.	GXP	$28.41	$0.98	5.13%	5.20%	5.26%	5.32%	5.39%	5.45%	5.51%	9.21%
IDACORP, Inc.	IDA	$65.84	$1.88	2.83%	3.28%	3.73%	4.17%	4.62%	5.07%	5.51%	8.11%
Otter Tail Corporation	OTTR	$31.79	$1.23	10.75%	9.88%	9.00%	8.13%	7.26%	6.39%	5.51%	11.37%
Pinnacle West Capital Corporation	PNW	$68.58	$2.38	4.07%	4.31%	4.55%	4.79%	5.03%	5.27%	5.51%	8.99%
PNM Resources, Inc.	PNM	$29.59	$0.80	9.92%	9.19%	8.45%	7.72%	6.98%	6.25%	5.51%	9.43%
Portland General Electric Company	POR	$38.62	$1.12	5.39%	5.41%	5.43%	5.45%	5.47%	5.49%	5.51%	8.66%
Southern Company	SO	$49.06	$2.10	3.67%	3.97%	4.28%	4.59%	4.90%	5.21%	5.51%	9.72%
Westar Energy, Inc.	WR	$41.50	$1.40	4.39%	4.58%	4.76%	4.95%	5.14%	5.33%	5.51%	8.96%
MEAN											**9.30%**

Notes:
[1] Source: Bloomberg Professional, equals 30-trading day average as of February 27, 2015.
[2] Source: Bloomberg Professional
[3] Source: Exhibit AEB-1
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit AEB-3
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

90-DAY MULTI-STAGE DCF -- AVERAGE FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$53.86	$2.02	6.00%	5.92%	5.84%	5.76%	5.68%	5.60%	5.51%	9.78%
American Electric Power Company, Inc.	AEP	$59.41	$2.12	4.78%	4.91%	5.03%	5.15%	5.27%	5.39%	5.51%	9.26%
Duke Energy Corporation	DUK	$82.74	$3.18	4.70%	4.84%	4.97%	5.11%	5.24%	5.38%	5.51%	9.54%
Empire District Electric Company	EDE	$28.44	$1.04	3.33%	3.70%	4.06%	4.42%	4.79%	5.15%	5.51%	9.00%
Eversource Energy	ES	$52.20	$1.67	6.88%	6.66%	6.43%	6.20%	5.97%	5.74%	5.51%	9.35%
Great Plains Energy Inc.	GXP	$27.53	$0.98	5.13%	5.20%	5.26%	5.32%	5.39%	5.45%	5.51%	9.34%
IDACORP, Inc.	IDA	$64.19	$1.88	2.83%	3.28%	3.73%	4.17%	4.62%	5.07%	5.51%	8.18%
Otter Tail Corporation	OTTR	$30.69	$1.23	10.75%	9.88%	9.00%	8.13%	7.26%	6.39%	5.51%	11.58%
Pinnacle West Capital Corporation	PNW	$65.83	$2.38	4.07%	4.31%	4.55%	4.79%	5.03%	5.27%	5.51%	9.14%
PNM Resources, Inc.	PNM	$29.24	$0.80	9.92%	9.19%	8.45%	7.72%	6.98%	6.25%	5.51%	9.48%
Portland General Electric Company	POR	$37.65	$1.12	5.39%	5.41%	5.43%	5.45%	5.47%	5.49%	5.51%	8.75%
Southern Company	SO	$48.38	$2.10	3.67%	3.97%	4.28%	4.59%	4.90%	5.21%	5.51%	9.78%
Westar Energy, Inc.	WR	$40.06	$1.40	4.39%	4.58%	4.76%	4.95%	5.14%	5.33%	5.51%	9.09%
MEAN											**9.40%**

Notes:
[1] Source: Bloomberg Professional, equals 90-trading day average as of February 27, 2015.
[2] Source: Bloomberg Professional
[3] Source: Exhibit AEB-1
[4] Equals [3] + ([9] – [3]) / 6
[5] Equals [4] + ([9] – [3]) / 6
[6] Equals [5] + ([9] – [3]) / 6
[7] Equals [6] + ([9] – [3]) / 6
[8] Equals [7] + ([9] – [3]) / 6
[9] Source: Exhibit AEB-3
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

180-DAY MULTI-STAGE DCF -- AVERAGE FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$50.95	$2.02	6.00%	5.92%	5.84%	5.76%	5.68%	5.60%	5.51%	10.02%
American Electric Power Company, Inc.	AEP	$56.29	$2.12	4.78%	4.91%	5.03%	5.15%	5.27%	5.39%	5.51%	9.47%
Duke Energy Corporation	DUK	$78.08	$3.18	4.70%	4.84%	4.97%	5.11%	5.24%	5.38%	5.51%	9.78%
Empire District Electric Company	EDE	$26.74	$1.04	3.33%	3.70%	4.06%	4.42%	4.79%	5.15%	5.51%	9.23%
Eversource Energy	ES	$48.78	$1.67	6.88%	6.66%	6.43%	6.20%	5.97%	5.74%	5.51%	9.62%
Great Plains Energy Inc.	GXP	$26.45	$0.98	5.13%	5.20%	5.26%	5.32%	5.39%	5.45%	5.51%	9.50%
IDACORP, Inc.	IDA	$59.74	$1.88	2.83%	3.28%	3.73%	4.17%	4.62%	5.07%	5.51%	8.40%
Otter Tail Corporation	OTTR	$29.53	$1.23	10.75%	9.88%	9.00%	8.13%	7.26%	6.39%	5.51%	11.81%
Pinnacle West Capital Corporation	PNW	$60.83	$2.38	4.07%	4.31%	4.55%	4.79%	5.03%	5.27%	5.51%	9.44%
PNM Resources, Inc.	PNM	$28.01	$0.80	9.92%	9.19%	8.45%	7.72%	6.98%	6.25%	5.51%	9.65%
Portland General Electric Company	POR	$35.46	$1.12	5.39%	5.41%	5.43%	5.45%	5.47%	5.49%	5.51%	8.95%
Southern Company	SO	$46.28	$2.10	3.67%	3.97%	4.28%	4.59%	4.90%	5.21%	5.51%	9.98%
Westar Energy, Inc.	WR	$38.09	$1.40	4.39%	4.58%	4.76%	4.95%	5.14%	5.33%	5.51%	9.28%
MEAN											**9.63%**

Notes:
[1] Source: Bloomberg Professional, equals 180-trading day average as of February 27, 2015.
[2] Source: Bloomberg Professional
[3] Source: Exhibit AEB-1
[4] Equals [3] + ([9] – [3]) / 6
[5] Equals [4] + ([9] – [3]) / 6
[6] Equals [5] + ([9] – [3]) / 6
[7] Equals [6] + ([9] – [3]) / 6
[8] Equals [7] + ([9] – [3]) / 6
[9] Source: Exhibit AEB-3
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

30-DAY MULTI-STAGE DCF -- MINIMUM FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$56.26	$2.02	6.00%	5.92%	5.84%	5.76%	5.68%	5.60%	5.51%	9.59%
American Electric Power Company, Inc.	AEP	$60.95	$2.12	4.50%	4.67%	4.84%	5.01%	5.18%	5.35%	5.51%	9.09%
Duke Energy Corporation	DUK	$84.07	$3.18	4.41%	4.59%	4.78%	4.96%	5.15%	5.33%	5.51%	9.40%
Empire District Electric Company	EDE	$28.31	$1.04	3.00%	3.42%	3.84%	4.26%	4.68%	5.10%	5.51%	8.94%
Eversource Energy	ES	$54.19	$1.67	6.25%	6.13%	6.00%	5.88%	5.76%	5.64%	5.51%	9.06%
Great Plains Energy Inc.	GXP	$28.41	$0.98	4.60%	4.75%	4.90%	5.06%	5.21%	5.36%	5.51%	9.09%
IDACORP, Inc.	IDA	$65.84	$1.88	1.50%	2.17%	2.84%	3.51%	4.18%	4.85%	5.51%	7.87%
Otter Tail Corporation	OTTR	$31.79	$1.23	6.00%	5.92%	5.84%	5.76%	5.68%	5.60%	5.51%	9.91%
Pinnacle West Capital Corporation	PNW	$68.58	$2.38	4.00%	4.25%	4.50%	4.76%	5.01%	5.26%	5.51%	8.97%
PNM Resources, Inc.	PNM	$29.59	$0.80	8.90%	8.34%	7.77%	7.21%	6.64%	6.08%	5.51%	9.19%
Portland General Electric Company	POR	$38.62	$1.12	5.00%	5.09%	5.17%	5.26%	5.34%	5.43%	5.51%	8.58%
Southern Company	SO	$49.06	$2.10	3.40%	3.75%	4.10%	4.46%	4.81%	5.16%	5.51%	9.64%
Westar Energy, Inc.	WR	$41.50	$1.40	3.37%	3.73%	4.08%	4.44%	4.80%	5.16%	5.51%	8.73%
MEAN											**9.08%**

Notes:
[1] Source: Bloomberg Professional, equals 30-trading day average as of February 27, 2015.
[2] Source: Bloomberg Professional
[3] Source: Exhibit AEB-1
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit AEB-3
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

90-DAY MULTI-STAGE DCF -- MINIMUM FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$53.86	$2.02	6.00%	5.92%	5.84%	5.76%	5.68%	5.60%	5.51%	9.78%
American Electric Power Company, Inc.	AEP	$59.41	$2.12	4.50%	4.67%	4.84%	5.01%	5.18%	5.35%	5.51%	9.19%
Duke Energy Corporation	DUK	$82.74	$3.18	4.41%	4.59%	4.78%	4.96%	5.15%	5.33%	5.51%	9.46%
Empire District Electric Company	EDE	$28.44	$1.04	3.00%	3.42%	3.84%	4.26%	4.68%	5.10%	5.51%	8.93%
Eversource Energy	ES	$52.20	$1.67	6.25%	6.13%	6.00%	5.88%	5.76%	5.64%	5.51%	9.20%
Great Plains Energy Inc.	GXP	$27.53	$0.98	4.60%	4.75%	4.90%	5.06%	5.21%	5.36%	5.51%	9.21%
IDACORP, Inc.	IDA	$64.19	$1.88	1.50%	2.17%	2.84%	3.51%	4.18%	4.85%	5.51%	7.94%
Otter Tail Corporation	OTTR	$30.69	$1.23	6.00%	5.92%	5.84%	5.76%	5.68%	5.60%	5.51%	10.07%
Pinnacle West Capital Corporation	PNW	$65.83	$2.38	4.00%	4.25%	4.50%	4.76%	5.01%	5.26%	5.51%	9.12%
PNM Resources, Inc.	PNM	$29.24	$0.80	8.90%	8.34%	7.77%	7.21%	6.64%	6.08%	5.51%	9.23%
Portland General Electric Company	POR	$37.65	$1.12	5.00%	5.09%	5.17%	5.26%	5.34%	5.43%	5.51%	8.66%
Southern Company	SO	$48.38	$2.10	3.40%	3.75%	4.10%	4.46%	4.81%	5.16%	5.51%	9.70%
Westar Energy, Inc.	WR	$40.06	$1.40	3.37%	3.73%	4.08%	4.44%	4.80%	5.16%	5.51%	8.85%
MEAN											**9.18%**

Notes:
[1] Source: Bloomberg Professional, equals 90-trading day average as of February 27, 2015.
[2] Source: Bloomberg Professional
[3] Source: Exhibit AEB-1
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit AEB-3
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

180-DAY MULTI-STAGE DCF -- MINIMUM FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$50.95	$2.02	6.00%	5.92%	5.84%	5.76%	5.68%	5.60%	5.51%	10.02%
American Electric Power Company, Inc.	AEP	$56.29	$2.12	4.50%	4.67%	4.84%	5.01%	5.18%	5.35%	5.51%	9.40%
Duke Energy Corporation	DUK	$78.08	$3.18	4.41%	4.59%	4.78%	4.96%	5.15%	5.33%	5.51%	9.70%
Empire District Electric Company	EDE	$26.74	$1.04	3.00%	3.42%	3.84%	4.26%	4.68%	5.10%	5.51%	9.15%
Eversource Energy	ES	$48.78	$1.67	6.25%	6.13%	6.00%	5.88%	5.76%	5.64%	5.51%	9.46%
Great Plains Energy Inc.	GXP	$26.45	$0.98	4.60%	4.75%	4.90%	5.06%	5.21%	5.36%	5.51%	9.36%
IDACORP, Inc.	IDA	$59.74	$1.88	1.50%	2.17%	2.84%	3.51%	4.18%	4.85%	5.51%	8.14%
Otter Tail Corporation	OTTR	$29.53	$1.23	6.00%	5.92%	5.84%	5.76%	5.68%	5.60%	5.51%	10.26%
Pinnacle West Capital Corporation	PNW	$60.83	$2.38	4.00%	4.25%	4.50%	4.76%	5.01%	5.26%	5.51%	9.43%
PNM Resources, Inc.	PNM	$28.01	$0.80	8.90%	8.34%	7.77%	7.21%	6.64%	6.08%	5.51%	9.40%
Portland General Electric Company	POR	$35.46	$1.12	5.00%	5.09%	5.17%	5.26%	5.34%	5.43%	5.51%	8.86%
Southern Company	SO	$46.28	$2.10	3.40%	3.75%	4.10%	4.46%	4.81%	5.16%	5.51%	9.90%
Westar Energy, Inc.	WR	$38.09	$1.40	3.37%	3.73%	4.08%	4.44%	4.80%	5.16%	5.51%	9.03%
MEAN											9.39%

Notes:
[1] Source: Bloomberg Professional, equals 180-trading day average as of February 27, 2015.
[2] Source: Bloomberg Professional
[3] Source: Exhibit AEB-1
[4] Equals [3] + ([9] – [3]) / 6
[5] Equals [4] + ([9] – [3]) / 6
[6] Equals [5] + ([9] – [3]) / 6
[7] Equals [6] + ([9] – [3]) / 6
[8] Equals [7] + ([9] – [3]) / 6
[9] Source: Exhibit AEB-3
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

30-DAY MULTI-STAGE DCF -- MAXIMUM FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$56.26	$2.02	6.00%	5.92%	5.84%	5.76%	5.68%	5.60%	5.51%	9.59%
American Electric Power Company, Inc.	AEP	$60.95	$2.12	5.05%	5.13%	5.20%	5.28%	5.36%	5.44%	5.51%	9.23%
Duke Energy Corporation	DUK	$84.07	$3.18	5.00%	5.09%	5.17%	5.26%	5.34%	5.43%	5.51%	9.55%
Empire District Electric Company	EDE	$28.31	$1.04	4.00%	4.25%	4.50%	4.76%	5.01%	5.26%	5.51%	9.18%
Eversource Energy	ES	$54.19	$1.67	8.00%	7.59%	7.17%	6.76%	6.34%	5.93%	5.51%	9.48%
Great Plains Energy Inc.	GXP	$28.41	$0.98	6.00%	5.92%	5.84%	5.76%	5.68%	5.60%	5.51%	9.43%
IDACORP, Inc.	IDA	$65.84	$1.88	4.00%	4.25%	4.50%	4.76%	5.01%	5.26%	5.51%	8.33%
Otter Tail Corporation	OTTR	$31.79	$1.23	15.50%	13.84%	12.17%	10.51%	8.84%	7.18%	5.51%	13.12%
Pinnacle West Capital Corporation	PNW	$68.58	$2.38	4.20%	4.42%	4.64%	4.86%	5.08%	5.30%	5.51%	9.02%
PNM Resources, Inc.	PNM	$29.59	$0.80	11.00%	10.09%	9.17%	8.26%	7.34%	6.43%	5.51%	9.70%
Portland General Electric Company	POR	$38.62	$1.12	5.90%	5.84%	5.77%	5.71%	5.64%	5.58%	5.51%	8.77%
Southern Company	SO	$49.06	$2.10	4.00%	4.25%	4.50%	4.76%	5.01%	5.26%	5.51%	9.81%
Westar Energy, Inc.	WR	$41.50	$1.40	6.00%	5.92%	5.84%	5.76%	5.68%	5.60%	5.51%	9.34%
MEAN											**9.58%**

Notes:
[1] Source: Bloomberg Professional, equals 30-trading day average as of February 27, 2015.
[2] Source: Bloomberg Professional
[3] Source: Exhibit AEB-1
[4] Equals [3] + ([9] – [3]) / 6
[5] Equals [4] + ([9] – [3]) / 6
[6] Equals [5] + ([9] – [3]) / 6
[7] Equals [6] + ([9] – [3]) / 6
[8] Equals [7] + ([9] – [3]) / 6
[9] Source: Exhibit AEB-3
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

90-DAY MULTI-STAGE DCF -- MAXIMUM FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$53.86	$2.02	6.00%	5.92%	5.84%	5.76%	5.68%	5.60%	5.51%	9.78%
American Electric Power Company, Inc.	AEP	$59.41	$2.12	5.05%	5.13%	5.20%	5.28%	5.36%	5.44%	5.51%	9.32%
Duke Energy Corporation	DUK	$82.74	$3.18	5.00%	5.09%	5.17%	5.26%	5.34%	5.43%	5.51%	9.61%
Empire District Electric Company	EDE	$28.44	$1.04	4.00%	4.25%	4.50%	4.76%	5.01%	5.26%	5.51%	9.16%
Eversource Energy	ES	$52.20	$1.67	8.00%	7.59%	7.17%	6.76%	6.34%	5.93%	5.51%	9.63%
Great Plains Energy Inc.	GXP	$27.53	$0.98	6.00%	5.92%	5.84%	5.76%	5.68%	5.60%	5.51%	9.56%
IDACORP, Inc.	IDA	$64.19	$1.88	4.00%	4.25%	4.50%	4.76%	5.01%	5.26%	5.51%	8.41%
Otter Tail Corporation	OTTR	$30.69	$1.23	15.50%	13.84%	12.17%	10.51%	8.84%	7.18%	5.51%	13.37%
Pinnacle West Capital Corporation	PNW	$65.83	$2.38	4.20%	4.42%	4.64%	4.86%	5.08%	5.30%	5.51%	9.17%
PNM Resources, Inc.	PNM	$29.24	$0.80	11.00%	10.09%	9.17%	8.26%	7.34%	6.43%	5.51%	9.74%
Portland General Electric Company	POR	$37.65	$1.12	5.90%	5.84%	5.77%	5.71%	5.64%	5.58%	5.51%	8.86%
Southern Company	SO	$48.38	$2.10	4.00%	4.25%	4.50%	4.76%	5.01%	5.26%	5.51%	9.87%
Westar Energy, Inc.	WR	$40.06	$1.40	6.00%	5.92%	5.84%	5.76%	5.68%	5.60%	5.51%	9.48%
MEAN											9.69%

Notes:
[1] Source: Bloomberg Professional, equals 90-trading day average as of February 27, 2015.
[2] Source: Bloomberg Professional
[3] Source: Exhibit AEB-1
[4] Equals [3] + ([9] – [3]) / 6
[5] Equals [4] + ([9] – [3]) / 6
[6] Equals [5] + ([9] – [3]) / 6
[7] Equals [6] + ([9] – [3]) / 6
[8] Equals [7] + ([9] – [3]) / 6
[9] Source: Exhibit AEB-3
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

180-DAY MULTI-STAGE DCF -- MAXIMUM FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$50.95	$2.02	6.00%	5.92%	5.84%	5.76%	5.68%	5.60%	5.51%	10.02%
American Electric Power Company, Inc.	AEP	$56.29	$2.12	5.05%	5.13%	5.20%	5.28%	5.36%	5.44%	5.51%	9.54%
Duke Energy Corporation	DUK	$78.08	$3.18	5.00%	5.09%	5.17%	5.26%	5.34%	5.43%	5.51%	9.87%
Empire District Electric Company	EDE	$26.74	$1.04	4.00%	4.25%	4.50%	4.76%	5.01%	5.26%	5.51%	9.40%
Eversource Energy	ES	$48.78	$1.67	8.00%	7.59%	7.17%	6.76%	6.34%	5.93%	5.51%	9.92%
Great Plains Energy Inc.	GXP	$26.45	$0.98	6.00%	5.92%	5.84%	5.76%	5.68%	5.60%	5.51%	9.72%
IDACORP, Inc.	IDA	$59.74	$1.88	4.00%	4.25%	4.50%	4.76%	5.01%	5.26%	5.51%	8.64%
Otter Tail Corporation	OTTR	$29.53	$1.23	15.50%	13.84%	12.17%	10.51%	8.84%	7.18%	5.51%	13.66%
Pinnacle West Capital Corporation	PNW	$60.83	$2.38	4.20%	4.42%	4.64%	4.86%	5.08%	5.30%	5.51%	9.48%
PNM Resources, Inc.	PNM	$28.01	$0.80	11.00%	10.09%	9.17%	8.26%	7.34%	6.43%	5.51%	9.93%
Portland General Electric Company	POR	$35.46	$1.12	5.90%	5.84%	5.77%	5.71%	5.64%	5.58%	5.51%	9.07%
Southern Company	SO	$46.28	$2.10	4.00%	4.25%	4.50%	4.76%	5.01%	5.26%	5.51%	10.08%
Westar Energy, Inc.	WR	$38.09	$1.40	6.00%	5.92%	5.84%	5.76%	5.68%	5.60%	5.51%	9.69%
MEAN											**9.92%**

Notes:
[1] Source: Bloomberg Professional, equals 180-trading day average as of February 27, 2015.
[2] Source: Bloomberg Professional
[3] Source: Exhibit AEB-1
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit AEB-3
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

Exhibit AEB-3

CALCULATION OF LONG-TERM GDP GROWTH RATE

Step 1	
Real GDP ($ Billions) [1]	
1929	$ 1,056.6
2014	$ 16,085.3
Compound Annual Growth Rate	**3.26%**
Step 2	
Consumer Price Index (YoY % Change) [2]	
2021-2025	2.30%
Average	2.30%
Consumer Price Index (All-Urban) [3]	
2025	2.90
2040	4.05
Compound Annual Growth Rate	2.26%
GDP Chain-type Price Index (2005=1.000) [3]	
2025	1.42
2040	1.91
Compound Annual Growth Rate	2.00%
Average Inflation Forecast	**2.19%**
Long-Term GDP Growth Rate	**5.51%**

Notes:
[1] Bureau of Economic Analysis, February 27, 2015
[2] Blue Chip Financial Forecasts, Vol. 33, No.12, December 1, 2014, at 14
[3] Energy Information Administration, Annual Energy Outlook 2014, Table 20

Exhibit AEB-4

BETA
AS OF FEBRUARY 27, 2015

		[1]	[2]
		Bloomberg	Value Line
ALLETE, Inc.	ALE	0.70	0.80
American Electric Power Company, Inc.	AEP	0.66	0.70
Duke Energy Corporation	DUK	0.46	0.60
Empire District Electric Company	EDE	0.55	0.70
Eversource Energy	ES	0.63	0.75
Great Plains Energy Inc.	GXP	0.72	0.85
IDACORP, Inc.	IDA	0.78	0.80
Otter Tail Corporation	OTTR	0.92	0.90
Pinnacle West Capital Corporation	PNW	0.73	0.70
PNM Resources, Inc.	PNM	0.73	0.85
Portland General Electric Company	POR	0.68	0.80
Southern Company	SO	0.48	0.55
Westar Energy, Inc.	WR	0.60	0.75
Mean		0.665	0.750

Notes:
[1] Source: Bloomberg Professional
[2] Source: Value Line; dated Dec. 19, 2014, Jan. 31, 2015, and Feb. 20, 2015.

Exhibit AEB-5

CAPITAL ASSET PRICING MODEL

	[4]	[5]	[6]	[7]
	Risk-Free Rate	Average Beta	Market Risk Premium	ROE
Proxy Group Average Bloomberg Beta				
[1] Current 30-day average of 30-year U.S. Treasury bond yield	2.50%	0.665	10.67%	9.59%
[2] Near-term projected 30-year U.S. Treasury bond yield (Q1 2015 - Q2 2016)	3.20%	0.665	9.97%	9.83%
[3] Projected 30-year U.S. Treasury bond yield (2016 - 2020)	4.90%	0.665	8.27%	10.40%
			Mean:	9.94%
Proxy Group Average Value Line Beta				
[1] Current 30-day average of 30-year U.S. Treasury bond yield	2.50%	0.750	10.67%	10.50%
[2] Near-term projected 30-year U.S. Treasury bond yield (Q1 2015 - Q2 2016)	3.20%	0.750	9.97%	10.68%
[3] Projected 30-year U.S. Treasury bond yield (2016 - 2020)	4.90%	0.750	8.27%	11.10%
			Mean:	10.76%

[1] Source: Bloomberg Professional
[2] Source: Blue Chip Financial Forecasts, Vol. 34, No. 2, February 1, 2015, at 2
[3] Source: Blue Chip Financial Forecasts, Vol. 33, No. 12, December 1, 2014, at 14
[4] See Notes [1], [2], and [3]
[5] Source: Exhibit AEB-4
[6] Source: Exhibit AEB-5, at 2
[7] Equals [4] + ([5] x [6])

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

[8] Estimated Weighted Average Dividend Yield		2.00%	
[9] Estimated Weighted Average Long-Term Growth Rate		11.06%	
[10] S&P 500 Estimated Required Market Return		13.17%	
[11] Risk-Free Rate	2.50%	3.20%	4.90%
[12] Implied Market Risk Premium	10.67%	9.97%	8.27%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
Alcoa Inc	AA	0.09%	0.81%	0.00%	16.40%	0.02%
LyondellBasell Industries NV	LYB	0.21%	3.26%	0.01%	6.50%	0.01%
American Express Co	AXP	0.43%	1.27%	0.01%	9.27%	0.04%
Verizon Communications Inc	VZ	1.07%	4.45%	0.05%	6.61%	0.07%
Avago Technologies Ltd	AVGO	0.17%	1.10%	0.00%	20.69%	0.04%
Boeing Co/The	BA	0.55%	2.41%	0.01%	10.73%	0.06%
Caterpillar Inc	CAT	0.26%	3.38%	0.01%	8.04%	0.02%
JPMorgan Chase & Co	JPM	1.19%	2.61%	0.03%	6.70%	0.08%
Chevron Corp	CVX	1.04%	4.01%	0.04%	4.29%	0.04%
Coca-Cola Co/The	KO	0.98%	3.05%	0.03%	5.33%	0.05%
AbbVie Inc	ABBV	0.50%	3.37%	0.02%	9.05%	0.05%
Walt Disney Co/The	DIS	0.92%	1.10%	0.01%	12.18%	0.11%
EI du Pont de Nemours & Co	DD	0.37%	2.41%	0.01%	6.83%	0.03%
Exxon Mobil Corp	XOM	1.93%	3.12%	0.06%	11.83%	0.23%
Phillips 66	PSX	0.22%	2.55%	0.01%	8.37%	0.02%
General Electric Co	GE	1.36%	3.54%	0.05%	8.26%	0.11%
Hewlett-Packard Co	HPQ	0.33%	1.84%	0.01%	3.67%	0.01%
Home Depot Inc/The	HD	0.79%	2.06%	0.02%	14.57%	0.11%
International Business Machines Corp	IBM	0.83%	2.72%	0.02%	7.38%	0.06%
Johnson & Johnson	JNJ	1.48%	2.73%	0.04%	6.45%	0.10%
McDonald's Corp	MCD	0.49%	3.44%	0.02%	8.22%	0.04%
Merck & Co Inc	MRK	0.86%	3.07%	0.03%	7.22%	0.06%
3M Co	MMM	0.56%	2.43%	0.01%	9.60%	0.05%
Bank of America Corp	BAC	0.87%	1.27%	0.01%	8.00%	0.07%
Pfizer Inc	PFE	1.09%	3.26%	0.04%	5.06%	0.06%
Procter & Gamble Co/The	PG	1.20%	3.02%	0.04%	8.00%	0.10%
AT&T Inc	T	0.93%	5.44%	0.05%	5.37%	0.05%
Travelers Cos Inc/The	TRV	0.18%	2.05%	0.00%	7.92%	0.01%
United Technologies Corp	UTX	0.58%	2.10%	0.01%	9.10%	0.05%
Analog Devices Inc	ADI	0.09%	2.73%	0.00%	10.82%	0.01%
Wal-Mart Stores Inc	WMT	1.41%	2.34%	0.03%	7.17%	0.10%
Cisco Systems Inc	CSCO	0.78%	2.85%	0.02%	7.80%	0.06%
Intel Corp	INTC	0.82%	2.89%	0.02%	9.56%	0.08%
General Motors Co	GM	0.31%	3.86%	0.01%	10.57%	0.03%
Microsoft Corp	MSFT	1.87%	2.83%	0.05%	8.04%	0.15%
Dollar General Corp	DG	0.11%	n/a	n/a	13.14%	0.02%
Kinder Morgan Inc/DE	KMI	0.45%	4.39%	0.02%	19.40%	0.09%
Citigroup Inc	C	0.83%	0.08%	0.00%	11.41%	0.09%
Nielsen NV	NLSN	0.09%	2.21%	0.00%	14.00%	0.01%
American International Group Inc	AIG	0.39%	0.90%	0.00%	8.38%	0.03%
Honeywell International Inc	HON	0.42%	2.01%	0.01%	10.01%	0.04%
Altria Group Inc	MO	0.58%	3.70%	0.02%	7.49%	0.04%
HCA Holdings Inc	HCA	0.16%	n/a	n/a	12.04%	0.02%
Under Armour Inc	UA	0.07%	n/a	n/a	23.10%	0.02%
International Paper Co	IP	0.12%	2.84%	0.00%	8.80%	0.01%
Abbott Laboratories	ABT	0.37%	2.03%	0.01%	10.84%	0.04%
Aflac Inc	AFL	0.14%	2.51%	0.00%	8.09%	0.01%
Air Products & Chemicals Inc	APD	0.17%	1.97%	0.00%	10.80%	0.02%
Airgas Inc	ARG	0.05%	1.88%	0.00%	11.90%	0.01%
Allergan Inc/United States	AGN	0.37%	0.09%	0.00%	17.33%	0.06%
Royal Caribbean Cruises Ltd	RCL	0.09%	1.57%	0.00%	19.20%	0.02%
American Electric Power Co Inc	AEP	0.15%	3.68%	0.01%	5.17%	0.01%
Hess Corp	HES	0.11%	1.33%	0.00%	3.73%	0.00%
Anadarko Petroleum Corp	APC	0.22%	1.28%	0.00%	3.16%	0.01%
Aon PLC	AON	0.15%	1.00%	0.00%	11.66%	0.02%
Apache Corp	APA	0.13%	1.52%	0.00%	1.73%	0.00%
Archer-Daniels-Midland Co	ADM	0.16%	2.34%	0.00%	5.65%	0.01%
AGL Resources Inc	GAS	0.03%	4.15%	0.00%	5.83%	0.00%
Automatic Data Processing Inc	ADP	0.22%	2.21%	0.00%	10.29%	0.02%
AutoZone Inc	AZO	0.11%	n/a	n/a	13.44%	0.01%
Avery Dennison Corp	AVY	0.03%	2.61%	0.00%	6.95%	0.00%
Avon Products Inc	AVP	0.02%	2.82%	0.00%	8.72%	0.00%
Baker Hughes Inc	BHI	0.14%	1.09%	0.00%	17.70%	0.03%
Ball Corp	BLL	0.05%	0.73%	0.00%	10.10%	0.01%
Bank of New York Mellon Corp/The	BK	0.23%	1.74%	0.00%	12.22%	0.03%
CR Bard Inc	BCR	0.07%	0.52%	0.00%	10.00%	0.01%
Baxter International Inc	BAX	0.20%	3.01%	0.01%	6.43%	0.01%
Becton Dickinson and Co	BDX	0.15%	1.64%	0.00%	9.21%	0.01%
Berkshire Hathaway Inc	BRK/B	0.93%	n/a	n/a	5.85%	0.05%
Best Buy Co Inc	BBY	0.07%	1.99%	0.00%	12.62%	0.01%
H&R Block Inc	HRB	0.05%	2.34%	0.00%	11.00%	0.01%
Boston Scientific Corp	BSX	0.12%	n/a	n/a	8.47%	0.01%
Bristol-Myers Squibb Co	BMY	0.53%	2.43%	0.01%	15.92%	0.08%
Brown-Forman Corp	BF/B	0.06%	1.37%	0.00%	7.11%	0.00%
Cabot Oil & Gas Corp	COG	0.06%	0.28%	0.00%	29.44%	0.02%
Campbell Soup Co	CPB	0.08%	2.68%	0.00%	2.89%	0.00%
Kansas City Southern	KSU	0.07%	1.14%	0.00%	15.63%	0.01%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
Carnival Corp	CCL	0.14%	2.27%	0.00%	17.11%	0.02%
CenturyLink Inc	CTL	0.11%	5.71%	0.01%	0.86%	0.00%
Chubb Corp/The	CB	0.12%	2.27%	0.00%	9.20%	0.01%
Cigna Corp	CI	0.16%	0.03%	0.00%	11.65%	0.02%
Frontier Communications Corp	FTR	0.04%	5.26%	0.00%	36.10%	0.02%
Clorox Co/The	CLX	0.07%	2.72%	0.00%	6.82%	0.01%
CMS Energy Corp	CMS	0.05%	3.30%	0.00%	5.87%	0.00%
Coca-Cola Enterprises Inc	CCE	0.06%	2.42%	0.00%	6.49%	0.00%
Colgate-Palmolive Co	CL	0.33%	2.15%	0.01%	9.68%	0.03%
Comerica Inc	CMA	0.04%	1.75%	0.00%	10.65%	0.00%
CA Inc	CA	0.07%	3.08%	0.00%	4.27%	0.00%
Computer Sciences Corp	CSC	0.05%	1.30%	0.00%	9.10%	0.00%
ConAgra Foods Inc	CAG	0.08%	2.86%	0.00%	9.37%	0.01%
Consolidated Edison Inc	ED	0.10%	4.12%	0.00%	3.14%	0.00%
Corning Inc	GLW	0.16%	1.97%	0.00%	5.43%	0.01%
CSX Corp	CSX	0.18%	1.87%	0.00%	12.22%	0.02%
Cummins Inc	CMI	0.13%	2.19%	0.00%	14.47%	0.02%
Danaher Corp	DHR	0.32%	0.62%	0.00%	11.25%	0.04%
Target Corp	TGT	0.25%	2.71%	0.01%	8.69%	0.02%
Deere & Co	DE	0.16%	2.65%	0.00%	6.38%	0.01%
Dominion Resources Inc/VA	D	0.22%	3.59%	0.01%	6.68%	0.01%
Dover Corp	DOV	0.06%	2.22%	0.00%	9.23%	0.01%
Dow Chemical Co/The	DOW	0.30%	3.41%	0.01%	8.60%	0.03%
Duke Energy Corp	DUK	0.29%	4.05%	0.01%	4.98%	0.01%
Eaton Corp PLC	ETN	0.17%	3.10%	0.01%	8.40%	0.01%
Ecolab Inc	ECL	0.18%	1.14%	0.00%	13.02%	0.02%
PerkinElmer Inc	PKI	0.03%	0.60%	0.00%	8.79%	0.00%
EMC Corp/MA	EMC	0.30%	1.59%	0.00%	10.65%	0.03%
Emerson Electric Co	EMR	0.21%	3.25%	0.01%	6.71%	0.01%
EOG Resources Inc	EOG	0.26%	0.75%	0.00%	9.68%	0.02%
Entergy Corp	ETR	0.07%	4.18%	0.00%	3.53%	0.00%
Equifax Inc	EFX	0.06%	1.24%	0.00%	13.80%	0.01%
EQT Corp	EQT	0.06%	0.15%	0.00%	30.00%	0.02%
XL Group PLC	XL	0.05%	1.77%	0.00%	5.87%	0.00%
Family Dollar Stores Inc	FDO	0.05%	1.57%	0.00%	6.63%	0.00%
FedEx Corp	FDX	0.26%	0.45%	0.00%	15.46%	0.04%
Macy's Inc	M	0.11%	1.96%	0.00%	8.27%	0.01%
FMC Corp	FMC	0.04%	0.95%	0.00%	10.00%	0.00%
Ford Motor Co	F	0.33%	3.67%	0.01%	15.39%	0.05%
NextEra Energy Inc	NEE	0.24%	2.98%	0.01%	6.28%	0.01%
Franklin Resources Inc	BEN	0.17%	1.11%	0.00%	10.44%	0.02%
Freeport-McMoRan Inc	FCX	0.12%	5.78%	0.01%	4.13%	0.00%
Gannett Co Inc	GCI	0.04%	2.26%	0.00%	4.67%	0.00%
Gap Inc/The	GPS	0.09%	2.21%	0.00%	11.18%	0.01%
General Dynamics Corp	GD	0.24%	1.79%	0.00%	8.22%	0.02%
General Mills Inc	GIS	0.17%	3.05%	0.01%	7.55%	0.01%
Genuine Parts Co	GPC	0.08%	2.56%	0.00%	6.87%	0.01%
WW Grainger Inc	GWW	0.08%	1.82%	0.00%	11.90%	0.01%
Halliburton Co	HAL	0.19%	1.68%	0.00%	17.10%	0.03%
Harley-Davidson Inc	HOG	0.07%	1.95%	0.00%	11.23%	0.01%
Harman International Industries Inc	HAR	0.05%	0.96%	0.00%	16.70%	0.01%
Joy Global Inc	JOY	0.02%	1.81%	0.00%	17.55%	0.00%
Harris Corp	HRS	0.04%	2.42%	0.00%	n/a	n/a
HCP Inc	HCP	0.10%	5.34%	0.01%	2.90%	0.00%
Helmerich & Payne Inc	HP	0.04%	4.10%	0.00%	n/a	n/a
Hershey Co/The	HSY	0.09%	2.06%	0.00%	9.50%	0.01%
Hormel Foods Corp	HRL	0.08%	1.71%	0.00%	5.90%	0.00%
Starwood Hotels & Resorts Worldwide Inc	HOT	0.07%	1.87%	0.00%	9.34%	0.01%
Mondelez International Inc	MDLZ	0.32%	1.62%	0.01%	8.57%	0.03%
CenterPoint Energy Inc	CNP	0.05%	4.76%	0.00%	5.20%	0.00%
Humana Inc	HUM	0.13%	0.68%	0.00%	10.33%	0.01%
Illinois Tool Works Inc	ITW	0.20%	1.96%	0.00%	9.20%	0.02%
Ingersoll-Rand PLC	IR	0.09%	1.73%	0.00%	9.96%	0.01%
Interpublic Group of Cos Inc/The	IPG	0.05%	2.15%	0.00%	11.13%	0.01%
International Flavors & Fragrances Inc	IFF	0.05%	1.54%	0.00%	10.30%	0.01%
Jacobs Engineering Group Inc	JEC	0.03%	n/a	n/a	8.45%	0.00%
Johnson Controls Inc	JCI	0.17%	2.05%	0.00%	10.94%	0.02%
Kellogg Co	K	0.12%	3.04%	0.00%	5.22%	0.01%
Perrigo Co PLC	PRGO	0.11%	0.32%	0.00%	13.24%	0.01%
Kimberly-Clark Corp	KMB	0.21%	3.21%	0.01%	6.97%	0.01%
Kimco Realty Corp	KIM	0.06%	3.65%	0.00%	4.14%	0.00%
Kohl's Corp	KSS	0.08%	2.44%	0.00%	6.73%	0.01%
Oracle Corp	ORCL	1.00%	1.10%	0.01%	9.24%	0.09%
Kroger Co/The	KR	0.18%	1.04%	0.00%	10.90%	0.02%
Legg Mason Inc	LM	0.03%	1.12%	0.00%	17.55%	0.01%
Leggett & Platt Inc	LEG	0.03%	2.75%	0.00%	n/a	n/a
Lennar Corp	LEN	0.05%	0.32%	0.00%	9.19%	0.00%
Leucadia National Corp	LUK	0.05%	1.05%	0.00%	n/a	n/a
Eli Lilly & Co	LLY	0.41%	2.85%	0.01%	12.94%	0.05%
L Brands Inc	LB	0.14%	2.18%	0.00%	12.94%	0.02%
Lincoln National Corp	LNC	0.08%	1.39%	0.00%	9.25%	0.01%
Loews Corp	L	0.08%	0.61%	0.00%	n/a	n/a
Lowe's Cos Inc	LOW	0.37%	1.24%	0.00%	16.68%	0.06%
Host Hotels & Resorts Inc	HST	0.08%	3.81%	0.00%	8.80%	0.01%
Marsh & McLennan Cos Inc	MMC	0.16%	1.97%	0.00%	12.85%	0.02%
Masco Corp	MAS	0.05%	1.37%	0.00%	11.38%	0.01%
Mattel Inc	MAT	0.05%	5.78%	0.00%	9.30%	0.00%
McGraw Hill Financial Inc	MHFI	0.15%	1.28%	0.00%	12.50%	0.02%
Medtronic PLC	MDT	0.58%	1.57%	0.01%	6.63%	0.04%
CVS Health Corp	CVS	0.61%	1.35%	0.01%	14.25%	0.09%
Micron Technology Inc	MU	0.17%	n/a	n/a	11.00%	0.02%

STANDARD AND POOR'S 500 INDEX

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Motorola Solutions Inc	MSI	0.08%	2.00%	0.00%	10.08%	0.01%
Murphy Oil Corp	MUR	0.05%	2.75%	0.00%	5.55%	0.00%
Mylan NV	MYL	0.11%	n/a	n/a	12.55%	0.01%
Laboratory Corp of America Holdings	LH	0.06%	n/a	n/a	10.73%	0.01%
Tenet Healthcare Corp	THC	0.02%	n/a	n/a	13.77%	0.00%
Newell Rubbermaid Inc	NWL	0.06%	1.93%	0.00%	9.43%	0.01%
Newmont Mining Corp	NEM	0.07%	0.38%	0.00%	0.63%	0.00%
Twenty-First Century Fox Inc	FOXA	0.24%	0.86%	0.00%	13.82%	0.03%
NIKE Inc	NKE	0.35%	1.15%	0.00%	13.08%	0.05%
NiSource Inc	NI	0.07%	2.42%	0.00%	6.00%	0.00%
Noble Energy Inc	NBL	0.10%	1.52%	0.00%	10.88%	0.01%
Norfolk Southern Corp	NSC	0.17%	2.16%	0.00%	12.64%	0.02%
Eversource Energy	ES	0.09%	3.23%	0.00%	6.70%	0.01%
Northrop Grumman Corp	NOC	0.17%	1.69%	0.00%	6.92%	0.01%
Wells Fargo & Co	WFC	1.47%	2.56%	0.04%	10.44%	0.15%
Nucor Corp	NUE	0.08%	3.17%	0.00%	11.45%	0.01%
PVH Corp	PVH	0.05%	0.14%	0.00%	12.40%	0.01%
Occidental Petroleum Corp	OXY	0.31%	3.70%	0.01%	8.00%	0.02%
Omnicom Group Inc	OMC	0.10%	2.51%	0.00%	6.20%	0.01%
ONEOK Inc	OKE	0.05%	5.47%	0.00%	11.37%	0.01%
Owens-Illinois Inc	OI	0.02%	n/a	n/a	5.24%	0.00%
PG&E Corp	PCG	0.13%	3.39%	0.00%	6.57%	0.01%
Parker-Hannifin Corp	PH	0.09%	2.05%	0.00%	8.92%	0.01%
PPL Corp	PPL	0.12%	4.37%	0.01%	3.24%	0.00%
PepsiCo Inc	PEP	0.76%	2.65%	0.02%	7.09%	0.05%
Exelon Corp	EXC	0.15%	3.66%	0.01%	6.82%	0.01%
ConocoPhillips	COP	0.42%	4.48%	0.02%	6.18%	0.03%
PulteGroup Inc	PHM	0.04%	1.42%	0.00%	11.19%	0.00%
Pinnacle West Capital Corp	PNW	0.04%	3.71%	0.00%	4.94%	0.00%
Pitney Bowes Inc	PBI	0.02%	3.24%	0.00%	n/a	n/a
Plum Creek Timber Co Inc	PCL	0.04%	4.05%	0.00%	0.00%	0.00%
PNC Financial Services Group Inc/The	PNC	0.25%	2.09%	0.01%	6.08%	0.02%
PPG Industries Inc	PPG	0.17%	1.14%	0.00%	7.97%	0.01%
Praxair Inc	PX	0.19%	2.24%	0.00%	10.25%	0.02%
Precision Castparts Corp	PCP	0.16%	0.06%	0.00%	10.78%	0.02%
Progressive Corp/The	PGR	0.08%	2.57%	0.00%	8.93%	0.01%
Public Service Enterprise Group Inc	PEG	0.11%	3.71%	0.00%	5.17%	0.01%
Raytheon Co	RTN	0.17%	2.22%	0.00%	6.64%	0.01%
Robert Half International Inc	RHI	0.04%	1.29%	0.00%	15.64%	0.01%
Ryder System Inc	R	0.03%	1.57%	0.00%	13.05%	0.00%
SCANA Corp	SCG	0.04%	3.83%	0.00%	5.50%	0.00%
Edison International	EIX	0.11%	2.60%	0.00%	4.70%	0.01%
Schlumberger Ltd	SLB	0.56%	2.38%	0.01%	13.11%	0.07%
Charles Schwab Corp/The	SCHW	0.20%	0.82%	0.00%	19.84%	0.04%
Sherwin-Williams Co/The	SHW	0.14%	0.94%	0.00%	14.00%	0.02%
JM Smucker Co/The	SJM	0.06%	2.22%	0.00%	5.46%	0.00%
Snap-on Inc	SNA	0.04%	1.44%	0.00%	5.80%	0.00%
AMETEK Inc	AME	0.07%	0.68%	0.00%	11.14%	0.01%
Southern Co/The	SO	0.21%	4.59%	0.01%	4.04%	0.01%
BB&T Corp	BBT	0.14%	2.52%	0.00%	12.57%	0.02%
Southwest Airlines Co	LUV	0.15%	0.56%	0.00%	14.55%	0.02%
Southwestern Energy Co	SWN	0.05%	n/a	n/a	13.02%	0.01%
Stanley Black & Decker Inc	SWK	0.08%	2.12%	0.00%	10.10%	0.01%
Public Storage	PSA	0.18%	2.84%	0.01%	5.43%	0.01%
SunTrust Banks Inc	STI	0.11%	1.95%	0.00%	20.65%	0.02%
Sysco Corp	SYY	0.12%	3.08%	0.00%	10.04%	0.01%
TECO Energy Inc	TE	0.02%	4.58%	0.00%	5.77%	0.00%
Tesoro Corp	TSO	0.06%	1.85%	0.00%	28.60%	0.02%
Texas Instruments Inc	TXN	0.32%	2.31%	0.01%	8.52%	0.03%
Textron Inc	TXT	0.06%	0.18%	0.00%	9.26%	0.01%
Thermo Fisher Scientific Inc	TMO	0.27%	0.46%	0.00%	16.03%	0.04%
Tiffany & Co	TIF	0.06%	1.72%	0.00%	11.88%	0.01%
TJX Cos Inc/The	TJX	0.25%	1.22%	0.00%	12.58%	0.03%
Torchmark Corp	TMK	0.04%	0.95%	0.00%	8.05%	0.00%
Total System Services Inc	TSS	0.04%	1.05%	0.00%	11.25%	0.00%
Tyco International Plc	TYC	0.09%	1.71%	0.00%	11.47%	0.01%
Union Pacific Corp	UNP	0.55%	1.83%	0.01%	13.04%	0.07%
UnitedHealth Group Inc	UNH	0.56%	1.32%	0.01%	10.99%	0.06%
Unum Group	UNM	0.04%	1.97%	0.00%	9.00%	0.00%
Marathon Oil Corp	MRO	0.10%	3.02%	0.00%	9.63%	0.01%
Varian Medical Systems Inc	VAR	0.05%	n/a	n/a	10.90%	0.01%
Ventas Inc	VTR	0.13%	3.11%	0.00%	3.94%	0.01%
VF Corp	VFC	0.17%	1.67%	0.00%	12.83%	0.02%
Vornado Realty Trust	VNO	0.11%	2.29%	0.00%	9.53%	0.01%
ADT Corp/The	ADT	0.03%	2.14%	0.00%	7.05%	0.00%
Vulcan Materials Co	VMC	0.06%	0.48%	0.00%	18.02%	0.01%
Weyerhaeuser Co	WY	0.10%	3.30%	0.00%	4.63%	0.00%
Whirlpool Corp	WHR	0.09%	1.42%	0.00%	23.49%	0.02%
Williams Cos Inc/The	WMB	0.19%	4.73%	0.01%	13.37%	0.03%
Integrys Energy Group Inc	TEG	0.03%	3.64%	0.00%	5.00%	0.00%
Wisconsin Energy Corp	WEC	0.06%	3.32%	0.00%	5.10%	0.00%
Xerox Corp	XRX	0.08%	2.05%	0.00%	10.20%	0.01%
Adobe Systems Inc	ADBE	0.21%	n/a	n/a	15.50%	0.03%
AES Corp/VA	AES	0.05%	3.08%	0.00%	6.25%	0.00%
Amgen Inc	AMGN	0.62%	2.00%	0.01%	10.48%	0.07%
Apple Inc	AAPL	3.89%	1.46%	0.06%	14.45%	0.56%
Autodesk Inc	ADSK	0.08%	n/a	n/a	17.00%	0.01%
Cintas Corp	CTAS	0.05%	1.02%	0.00%	11.26%	0.01%
Comcast Corp	CMCSA	0.66%	1.68%	0.01%	12.86%	0.08%
Molson Coors Brewing Co	TAP	0.06%	2.16%	0.00%	2.91%	0.00%
KLA-Tencor Corp	KLAC	0.05%	3.08%	0.00%	3.62%	0.00%

STANDARD AND POOR'S 500 INDEX

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Marriott International Inc/MD	MAR	0.12%	0.96%	0.00%	10.63%	0.01%
McCormick & Co Inc/MD	MKC	0.05%	2.12%	0.00%	7.23%	0.00%
Nordstrom Inc	JWN	0.08%	1.84%	0.00%	10.15%	0.01%
PACCAR Inc	PCAR	0.12%	1.37%	0.00%	9.58%	0.01%
Costco Wholesale Corp	COST	0.34%	0.97%	0.00%	10.39%	0.03%
Sigma-Aldrich Corp	SIAL	0.09%	0.67%	0.00%	5.14%	0.00%
St Jude Medical Inc	STJ	0.10%	1.74%	0.00%	10.20%	0.01%
Stryker Corp	SYK	0.19%	1.46%	0.00%	11.73%	0.02%
Tyson Foods Inc	TSN	0.07%	0.97%	0.00%	15.65%	0.01%
Altera Corp	ALTR	0.06%	1.95%	0.00%	11.47%	0.01%
Applied Materials Inc	AMAT	0.16%	1.60%	0.00%	12.93%	0.02%
Time Warner Inc	TWX	0.35%	1.71%	0.01%	11.06%	0.04%
Bed Bath & Beyond Inc	BBBY	0.07%	n/a	n/a	7.97%	0.01%
Cardinal Health Inc	CAH	0.15%	1.56%	0.00%	11.45%	0.02%
Celgene Corp	CELG	0.51%	n/a	n/a	26.12%	0.13%
Cerner Corp	CERN	0.13%	n/a	n/a	17.97%	0.02%
Cincinnati Financial Corp	CINF	0.05%	3.49%	0.00%	n/a	n/a
Cablevision Systems Corp	CVC	0.02%	3.19%	0.00%	-0.24%	0.00%
DR Horton Inc	DHI	0.05%	0.92%	0.00%	11.57%	0.01%
Flowserve Corp	FLS	0.04%	1.16%	0.00%	9.02%	0.00%
Electronic Arts Inc	EA	0.09%	n/a	n/a	16.00%	0.01%
Express Scripts Holding Co	ESRX	0.32%	n/a	n/a	12.91%	0.04%
Expeditors International of Washington Inc	EXPD	0.05%	1.33%	0.00%	8.92%	0.00%
Fastenal Co	FAST	0.06%	2.70%	0.00%	16.25%	0.01%
M&T Bank Corp	MTB	0.08%	2.31%	0.00%	9.81%	0.01%
Fiserv Inc	FISV	0.10%	n/a	n/a	12.76%	0.01%
Fifth Third Bancorp	FITB	0.08%	2.69%	0.00%	10.45%	0.01%
Gilead Sciences Inc	GILD	0.80%	1.66%	0.01%	19.34%	0.16%
Hasbro Inc	HAS	0.04%	2.95%	0.00%	10.00%	0.00%
Huntington Bancshares Inc/OH	HBAN	0.05%	2.19%	0.00%	7.76%	0.00%
Health Care REIT Inc	HCN	0.14%	4.28%	0.01%	6.05%	0.01%
Biogen Idec Inc	BIIB	0.50%	n/a	n/a	17.84%	0.09%
Linear Technology Corp	LLTC	0.06%	2.49%	0.00%	9.35%	0.01%
Range Resources Corp	RRC	0.04%	0.32%	0.00%	22.76%	0.01%
Nabors Industries Ltd	NBR	0.02%	1.87%	0.00%	7.94%	0.00%
Noble Corp plc	NE	0.02%	9.01%	0.00%	-12.37%	0.00%
Northern Trust Corp	NTRS	0.08%	1.89%	0.00%	12.52%	0.01%
Paychex Inc	PAYX	0.09%	3.05%	0.00%	9.58%	0.01%
People's United Financial Inc	PBCT	0.02%	4.36%	0.00%	13.19%	0.00%
Patterson Cos Inc	PDCO	0.03%	1.60%	0.00%	8.80%	0.00%
Pall Corp	PLL	0.06%	1.21%	0.00%	11.19%	0.01%
QUALCOMM Inc	QCOM	0.62%	2.32%	0.01%	10.94%	0.07%
Roper Industries Inc	ROP	0.09%	0.60%	0.00%	11.83%	0.01%
Ross Stores Inc	ROST	0.11%	0.89%	0.00%	13.36%	0.02%
AutoNation Inc	AN	0.04%	n/a	n/a	12.48%	0.00%
Starbucks Corp	SBUX	0.36%	1.37%	0.00%	17.63%	0.06%
KeyCorp	KEY	0.06%	1.87%	0.00%	7.33%	0.00%
Staples Inc	SPLS	0.06%	2.86%	0.00%	1.08%	0.00%
State Street Corp	STT	0.16%	1.61%	0.00%	13.30%	0.02%
US Bancorp/MN	USB	0.41%	2.20%	0.01%	8.33%	0.03%
Symantec Corp	SYMC	0.09%	2.38%	0.00%	7.82%	0.01%
T Rowe Price Group Inc	TROW	0.11%	2.52%	0.00%	12.23%	0.01%
Kraft Foods Group Inc	KRFT	0.20%	3.43%	0.01%	7.34%	0.01%
Waste Management Inc	WM	0.13%	2.83%	0.00%	8.20%	0.01%
CBS Corp	CBS	0.14%	1.02%	0.00%	15.13%	0.02%
Actavis plc	ACT	0.42%	n/a	n/a	19.89%	0.08%
Whole Foods Market Inc	WFM	0.11%	0.92%	0.00%	13.35%	0.01%
Constellation Brands Inc	STZ	0.10%	n/a	n/a	5.12%	0.01%
Xilinx Inc	XLNX	0.06%	2.74%	0.00%	9.20%	0.01%
DENTSPLY International Inc	XRAY	0.04%	0.55%	0.00%	9.88%	0.00%
Zions Bancorporation	ZION	0.03%	0.60%	0.00%	8.83%	0.00%
Denbury Resources Inc	DNR	0.02%	2.98%	0.00%	3.90%	0.00%
Invesco Ltd	IVZ	0.09%	2.48%	0.00%	12.04%	0.01%
Intuit Inc	INTU	0.14%	1.02%	0.00%	15.12%	0.02%
Morgan Stanley	MS	0.36%	1.12%	0.00%	15.74%	0.06%
Microchip Technology Inc	MCHP	0.05%	2.79%	0.00%	10.90%	0.01%
ACE Ltd	ACE	0.19%	2.28%	0.00%	8.40%	0.02%
Chesapeake Energy Corp	CHK	0.06%	2.10%	0.00%	1.72%	0.00%
O'Reilly Automotive Inc	ORLY	0.11%	n/a	n/a	16.33%	0.02%
Allstate Corp/The	ALL	0.15%	1.70%	0.00%	8.73%	0.01%
FLIR Systems Inc	FLIR	0.02%	1.36%	0.00%	14.33%	0.00%
Equity Residential	EQR	0.15%	2.60%	0.00%	7.84%	0.01%
BorgWarner Inc	BWA	0.07%	0.85%	0.00%	12.79%	0.01%
Newfield Exploration Co	NFX	0.03%	n/a	n/a	13.50%	0.00%
Urban Outfitters Inc	URBN	0.03%	n/a	n/a	15.91%	0.00%
Simon Property Group Inc	SPG	0.31%	2.94%	0.01%	7.44%	0.02%
Eastman Chemical Co	EMN	0.06%	2.15%	0.00%	7.14%	0.00%
AvalonBay Communities Inc	AVB	0.12%	2.97%	0.00%	7.61%	0.01%
Prudential Financial Inc	PRU	0.19%	2.87%	0.01%	11.00%	0.02%
United Parcel Service Inc	UPS	0.37%	2.87%	0.01%	11.79%	0.04%
Apartment Investment & Management Co	AIV	0.03%	2.97%	0.00%	7.81%	0.00%
Walgreens Boots Alliance Inc	WBA	0.47%	1.62%	0.01%	14.79%	0.07%
McKesson Corp	MCK	0.28%	0.42%	0.00%	15.76%	0.04%
Lockheed Martin Corp	LMT	0.33%	3.00%	0.01%	8.73%	0.03%
AmerisourceBergen Corp	ABC	0.12%	1.13%	0.00%	10.21%	0.01%
Cameron International Corp	CAM	0.05%	n/a	n/a	8.77%	0.00%
Capital One Financial Corp	COF	0.23%	1.52%	0.00%	5.58%	0.01%
Waters Corp	WAT	0.05%	n/a	n/a	9.66%	0.01%
Dollar Tree Inc	DLTR	0.09%	n/a	n/a	15.12%	0.01%
Darden Restaurants Inc	DRI	0.04%	3.44%	0.00%	12.66%	0.01%
SanDisk Corp	SNDK	0.09%	1.50%	0.00%	14.13%	0.01%

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Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
Diamond Offshore Drilling Inc	DO	0.02%	1.64%	0.00%	-12.45%	0.00%
NetApp Inc	NTAP	0.06%	1.71%	0.00%	11.64%	0.01%
Citrix Systems Inc	CTXS	0.05%	n/a	n/a	13.80%	0.01%
Goodyear Tire & Rubber Co/The	GT	0.04%	0.90%	0.00%	8.94%	0.00%
DaVita HealthCare Partners Inc	DVA	0.08%	n/a	n/a	9.93%	0.01%
Hartford Financial Services Group Inc/The	HIG	0.09%	1.76%	0.00%	9.50%	0.01%
Iron Mountain Inc	IRM	0.04%	5.17%	0.00%	12.33%	0.00%
Estee Lauder Cos Inc/The	EL	0.10%	1.16%	0.00%	10.28%	0.01%
Lorillard Inc	LO	0.13%	3.86%	0.00%	8.29%	0.01%
Yahoo! Inc	YHOO	0.22%	n/a	n/a	10.75%	0.02%
Principal Financial Group Inc	PFG	0.08%	2.81%	0.00%	13.50%	0.01%
Allegheny Technologies Inc	ATI	0.02%	2.14%	0.00%	16.10%	0.00%
Stericycle Inc	SRCL	0.06%	n/a	n/a	14.80%	0.01%
Universal Health Services Inc	UHS	0.05%	0.35%	0.00%	9.04%	0.00%
E*TRADE Financial Corp	ETFC	0.04%	n/a	n/a	29.65%	0.01%
National Oilwell Varco Inc	NOV	0.12%	3.39%	0.00%	2.38%	0.00%
Quest Diagnostics Inc	DGX	0.05%	2.17%	0.00%	10.33%	0.01%
Rockwell Automation Inc	ROK	0.08%	2.22%	0.00%	8.91%	0.01%
American Tower Corp	AMT	0.20%	1.53%	0.00%	21.13%	0.04%
Regeneron Pharmaceuticals Inc	REGN	0.22%	n/a	n/a	18.08%	0.04%
Amazon.com Inc	AMZN	0.92%	n/a	n/a	35.94%	0.33%
Ralph Lauren Corp	RL	0.04%	1.46%	0.00%	11.74%	0.01%
Boston Properties Inc	BXP	0.11%	1.89%	0.00%	7.22%	0.01%
Amphenol Corp	APH	0.09%	0.89%	0.00%	10.04%	0.01%
Pioneer Natural Resources Co	PXD	0.12%	0.05%	0.00%	18.00%	0.02%
Valero Energy Corp	VLO	0.17%	2.59%	0.00%	4.57%	0.01%
L-3 Communications Holdings Inc	LLL	0.06%	2.01%	0.00%	7.61%	0.00%
Western Union Co/The	WU	0.05%	3.18%	0.00%	8.97%	0.00%
CH Robinson Worldwide Inc	CHRW	0.06%	2.05%	0.00%	11.48%	0.01%
Accenture PLC	ACN	0.29%	2.27%	0.01%	10.50%	0.03%
Yum! Brands Inc	YUM	0.18%	2.02%	0.00%	11.18%	0.02%
Prologis Inc	PLD	0.11%	3.37%	0.00%	7.26%	0.01%
FirstEnergy Corp	FE	0.08%	4.12%	0.00%	-4.41%	0.00%
VeriSign Inc	VRSN	0.04%	n/a	n/a	10.57%	0.00%
Quanta Services Inc	PWR	0.03%	n/a	n/a	10.58%	0.00%
Ameren Corp	AEE	0.05%	3.87%	0.00%	7.20%	0.00%
Broadcom Corp	BRCM	0.13%	1.24%	0.00%	11.98%	0.02%
NVIDIA Corp	NVDA	0.06%	1.54%	0.00%	10.72%	0.01%
Sealed Air Corp	SEE	0.05%	1.10%	0.00%	9.53%	0.00%
Cognizant Technology Solutions Corp	CTSH	0.20%	n/a	n/a	16.65%	0.03%
Intuitive Surgical Inc	ISRG	0.10%	n/a	n/a	7.44%	0.01%
CONSOL Energy Inc	CNX	0.04%	0.78%	0.00%	8.05%	0.00%
Aetna Inc	AET	0.18%	1.00%	0.00%	11.91%	0.02%
Affiliated Managers Group Inc	AMG	0.06%	n/a	n/a	15.00%	0.01%
Republic Services Inc	RSG	0.08%	2.74%	0.00%	5.15%	0.00%
eBay Inc	EBAY	0.36%	n/a	n/a	13.48%	0.05%
Goldman Sachs Group Inc/The	GS	0.43%	1.26%	0.01%	18.03%	0.08%
Sempra Energy	SRE	0.14%	2.59%	0.00%	7.68%	0.01%
Moody's Corp	MCO	0.10%	1.40%	0.00%	13.50%	0.01%
Priceline Group Inc/The	PCLN	0.33%	n/a	n/a	19.82%	0.07%
F5 Networks Inc	FFIV	0.04%	n/a	n/a	15.47%	0.01%
Akamai Technologies Inc	AKAM	0.06%	n/a	n/a	15.83%	0.01%
QEP Resources Inc	QEP	0.02%	0.37%	0.00%	15.00%	0.00%
Reynolds American Inc	RAI	0.21%	3.54%	0.01%	9.05%	0.02%
Devon Energy Corp	DVN	0.13%	1.56%	0.00%	5.51%	0.01%
Google Inc	GOOGL	0.84%	n/a	n/a	16.59%	0.14%
Red Hat Inc	RHT	0.07%	n/a	n/a	16.77%	0.01%
Hudson City Bancorp Inc	HCBK	0.03%	1.64%	0.00%	-3.00%	0.00%
Netflix Inc	NFLX	0.15%	n/a	n/a	36.87%	0.06%
Allegion PLC	ALLE	0.03%	0.69%	0.00%	n/a	n/a
Agilent Technologies Inc	A	0.07%	0.95%	0.00%	5.10%	0.00%
Anthem Inc	ANTM	0.20%	1.71%	0.00%	10.20%	0.02%
CME Group Inc/IL	CME	0.17%	2.08%	0.00%	12.43%	0.02%
Juniper Networks Inc	JNPR	0.05%	1.67%	0.00%	11.14%	0.01%
BlackRock Inc	BLK	0.32%	2.35%	0.01%	12.14%	0.04%
DTE Energy Co	DTE	0.08%	3.36%	0.00%	5.38%	0.00%
NASDAQ OMX Group Inc/The	NDAQ	0.04%	1.20%	0.00%	9.42%	0.00%
Philip Morris International Inc	PM	0.67%	4.82%	0.03%	3.42%	0.02%
Time Warner Cable Inc	TWC	0.23%	1.95%	0.00%	10.04%	0.02%
salesforce.com inc	CRM	0.23%	n/a	n/a	23.40%	0.05%
Windstream Holdings Inc	WIN	0.02%	12.67%	0.00%	-1.00%	0.00%
MetLife Inc	MET	0.30%	2.75%	0.01%	7.15%	0.02%
Monsanto Co	MON	0.30%	1.63%	0.00%	8.15%	0.02%
Coach Inc	COH	0.06%	3.10%	0.00%	11.21%	0.01%
Fluor Corp	FLR	0.04%	1.45%	0.00%	7.54%	0.00%
Dun & Bradstreet Corp/The	DNB	0.02%	1.40%	0.00%	10.70%	0.00%
Edwards Lifesciences Corp	EW	0.07%	n/a	n/a	13.30%	0.01%
Ameriprise Financial Inc	AMP	0.13%	1.74%	0.00%	13.00%	0.02%
Xcel Energy Inc	XEL	0.09%	3.63%	0.00%	5.00%	0.00%
Rockwell Collins Inc	COL	0.06%	1.35%	0.00%	10.38%	0.01%
FMC Technologies Inc	FTI	0.05%	n/a	n/a	14.00%	0.01%
Zimmer Holdings Inc	ZMH	0.11%	0.73%	0.00%	9.40%	0.01%
CBRE Group Inc	CBG	0.06%	n/a	n/a	11.80%	0.01%
MasterCard Inc	MA	0.52%	0.71%	0.00%	17.07%	0.09%
GameStop Corp	GME	0.02%	3.57%	0.00%	15.30%	0.00%
CarMax Inc	KMX	0.07%	n/a	n/a	15.02%	0.01%
Intercontinental Exchange Inc	ICE	0.14%	1.10%	0.00%	15.19%	0.02%
Fidelity National Information Services Inc	FIS	0.10%	1.54%	0.00%	13.30%	0.01%
Chipotle Mexican Grill Inc	CMG	0.11%	n/a	n/a	20.93%	0.02%
MeadWestvaco Corp	MWV	0.05%	1.88%	0.00%	11.23%	0.01%
Pepco Holdings Inc	POM	0.04%	3.98%	0.00%	n/a	n/a

STANDARD AND POOR'S 500 INDEX

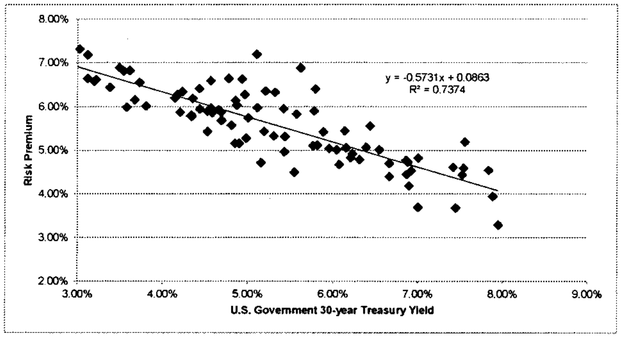
Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
Wynn Resorts Ltd	WYNN	0.08%	4.21%	0.00%	10.67%	0.01%
DIRECTV	DTV	0.23%	n/a	n/a	6.00%	0.01%
Hospira Inc	HSP	0.08%	n/a	n/a	16.70%	0.01%
Assurant Inc	AIZ	0.02%	1.76%	0.00%	7.66%	0.00%
NRG Energy Inc	NRG	0.04%	2.42%	0.00%	n/a	n/a
Genworth Financial Inc	GNW	0.02%	n/a	n/a	5.00%	0.00%
Regions Financial Corp	RF	0.07%	2.08%	0.00%	5.66%	0.00%
Teradata Corp	TDC	0.03%	n/a	n/a	10.07%	0.00%
Mosaic Co/The	MOS	0.10%	1.88%	0.00%	8.90%	0.01%
Expedia Inc	EXPE	0.05%	0.78%	0.00%	14.95%	0.01%
Discovery Communications Inc	DISCA	0.02%	n/a	n/a	18.08%	0.00%
CF Industries Holdings Inc	CF	0.08%	1.96%	0.00%	13.44%	0.01%
Viacom Inc	VIAB	0.13%	1.89%	0.00%	10.77%	0.01%
Google Inc	GOOG	0.99%	n/a	n/a	16.59%	0.16%
Wyndham Worldwide Corp	WYN	0.06%	1.84%	0.00%	10.00%	0.01%
Spectra Energy Corp	SE	0.12%	4.17%	0.01%	7.53%	0.01%
First Solar Inc	FSLR	0.03%	n/a	n/a	-3.81%	0.00%
Ensco PLC	ESV	0.03%	2.45%	0.00%	-3.43%	0.00%
Mead Johnson Nutrition Co	MJN	0.11%	1.58%	0.00%	10.10%	0.01%
TE Connectivity Ltd	TEL	0.15%	1.61%	0.00%	11.35%	0.02%
Discover Financial Services	DFS	0.14%	1.57%	0.00%	10.90%	0.02%
TripAdvisor Inc	TRIP	0.06%	n/a	n/a	22.03%	0.01%
Dr Pepper Snapple Group Inc	DPS	0.08%	2.44%	0.00%	5.45%	0.00%
Scripps Networks Interactive Inc	SNI	0.04%	1.27%	0.00%	9.80%	0.00%
Visa Inc	V	0.69%	0.71%	0.00%	17.74%	0.12%
CareFusion Corp	CFN	0.06%	n/a	n/a	12.00%	0.01%
Xylem Inc/NY	XYL	0.03%	1.58%	0.00%	11.45%	0.00%
Marathon Petroleum Corp	MPC	0.15%	1.90%	0.00%	9.70%	0.01%
Tractor Supply Co	TSCO	0.06%	0.73%	0.00%	15.68%	0.01%
Level 3 Communications Inc	LVLT	0.10%	n/a	n/a	8.00%	0.01%
Transocean Ltd	RIG	0.03%	3.72%	0.00%	-13.00%	0.00%
Essex Property Trust Inc	ESS	0.07%	2.59%	0.00%	6.96%	0.01%
General Growth Properties Inc	GGP	0.13%	2.34%	0.00%	8.02%	0.01%
Seagate Technology PLC	STX	0.10%	3.53%	0.00%	8.13%	0.01%
Western Digital Corp	WDC	0.13%	1.87%	0.00%	5.35%	0.01%
Fossil Group Inc	FOSL	0.02%	n/a	n/a	12.40%	0.00%
Lam Research Corp	LRCX	0.07%	0.87%	0.00%	7.32%	0.01%
Mohawk Industries Inc	MHK	0.07%	n/a	n/a	10.95%	0.01%
Pentair PLC	PNR	0.06%	1.93%	0.00%	16.93%	0.01%
Monster Beverage Corp	MNST	0.12%	n/a	n/a	19.32%	0.02%
Vertex Pharmaceuticals Inc	VRTX	0.15%	n/a	n/a	23.98%	0.04%
Facebook Inc	FB	0.92%	n/a	n/a	30.80%	0.28%
United Rentals Inc	URI	0.05%	n/a	n/a	23.06%	0.01%
Navient Corp	NAVI	0.04%	2.99%	0.00%	n/a	n/a
Delta Air Lines Inc	DAL	0.19%	0.81%	0.00%	25.43%	0.05%
Mallinckrodt PLC	MNK	0.07%	n/a	n/a	15.73%	0.01%
PetSmart Inc	PETM	0.04%	0.94%	0.00%	13.91%	0.01%
Keurig Green Mountain Inc	GMCR	0.11%	0.90%	0.00%	15.00%	0.02%
Macerich Co/The	MAC	0.07%	3.11%	0.00%	5.92%	0.00%
Martin Marietta Materials Inc	MLM	0.05%	1.12%	0.00%	19.18%	0.01%
Alexion Pharmaceuticals Inc	ALXN	0.19%	n/a	n/a	25.60%	0.05%
Endo International PLC	ENDP	0.07%	n/a	n/a	8.78%	0.01%
News Corp	NWSA	0.03%	n/a	n/a	10.90%	0.00%
Crown Castle International Corp	CCI	0.15%	3.80%	0.01%	26.20%	0.04%
Delphi Automotive PLC	DLPH	0.12%	1.27%	0.00%	14.88%	0.02%
Michael Kors Holdings Ltd	KORS	0.07%	n/a	n/a	28.67%	0.02%
Alliance Data Systems Corp	ADS	0.09%	n/a	n/a	14.02%	0.01%
Garmin Ltd	GRMN	0.05%	4.11%	0.00%	8.03%	0.00%
Cimarex Energy Co	XEC	0.05%	0.58%	0.00%	-10.90%	-0.01%
Zoetis Inc	ZTS	0.12%	0.72%	0.00%	11.70%	0.01%
Discovery Communications Inc	DISCK	0.05%	n/a	n/a	18.08%	0.01%

Notes:
[8] Equals sum of Col. [15]
[9] Equals sum of Col. [17]
[10] Equals ([8] x (1 + (0.5 x [9]))) + [9]
[11] Source: Exhibit AEB-5, at 1
[12] Equals [10] – [11]
[13] Equals weight in S&P 500 based on market capitalization
[14] Source: Bloomberg Professional
[15] Equals [13] x [14]
[16] Source: Bloomberg Professional
[17] Equals [13] x [16]

Exhibit AEB-6

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
	Average Authorized Electric ROE	30-year U.S. Treasury Bond	Risk Premium
1992.1	12.38%	7.84%	4.55%
1992.2	11.83%	7.88%	3.94%
1992.3	12.03%	7.42%	4.62%
1992.4	12.14%	7.54%	4.60%
1993.1	11.84%	7.01%	4.83%
1993.2	11.64%	6.86%	4.78%
1993.3	11.15%	6.23%	4.92%
1993.4	11.04%	6.21%	4.84%
1994.1	11.07%	6.66%	4.40%
1994.2	11.13%	7.45%	3.68%
1994.3	12.75%	7.55%	5.20%
1994.4	11.24%	7.95%	3.29%
1995.1	11.96%	7.52%	4.44%
1995.2	11.32%	6.87%	4.45%
1995.3	11.37%	6.66%	4.71%
1995.4	11.58%	6.14%	5.45%
1996.1	11.46%	6.39%	5.07%
1996.2	11.46%	6.92%	4.54%
1996.3	10.70%	7.00%	3.70%
1996.4	11.56%	6.54%	5.02%
1997.1	11.08%	6.90%	4.18%
1997.2	11.62%	6.88%	4.73%
1997.3	12.00%	6.44%	5.56%
1997.4	11.06%	6.04%	5.02%
1998.1	11.31%	5.89%	5.43%
1998.2	12.20%	5.79%	6.41%
1998.3	11.65%	5.32%	6.33%
1998.4	12.30%	5.11%	7.20%
1999.1	10.40%	5.43%	4.97%
1999.2	10.94%	5.82%	5.12%
1999.3	10.75%	6.07%	4.68%
1999.4	11.10%	6.31%	4.79%
2000.1	11.21%	6.15%	5.06%
2000.2	11.00%	5.95%	5.05%
2000.3	11.68%	5.78%	5.90%
2000.4	12.50%	5.62%	6.88%
2001.1	11.38%	5.42%	5.96%
2001.2	10.88%	5.77%	5.11%
2001.3	10.76%	5.44%	5.32%
2001.4	11.57%	5.21%	6.36%
2002.1	10.05%	5.55%	4.50%
2002.2	11.41%	5.57%	5.83%
2002.3	11.25%	4.96%	6.29%
2002.4	11.57%	4.93%	6.63%
2003.1	11.43%	4.78%	6.65%
2003.2	11.16%	4.57%	6.60%
2003.3	9.88%	5.15%	4.72%
2003.4	11.09%	5.11%	5.98%
2004.1	11.00%	4.86%	6.14%
2004.2	10.64%	5.31%	5.33%
2004.3	10.75%	5.01%	5.74%
2004.4	10.91%	4.87%	6.04%
2005.1	10.56%	4.69%	5.87%
2005.2	10.13%	4.34%	5.78%
2005.3	10.85%	4.43%	6.41%
2005.4	10.59%	4.66%	5.93%
2006.1	10.38%	4.69%	5.69%
2006.2	10.63%	5.19%	5.44%
2006.3	10.06%	4.90%	5.16%
2006.4	10.39%	4.70%	5.69%
2007.1	10.39%	4.81%	5.58%
2007.2	10.27%	4.98%	5.28%
2007.3	10.02%	4.85%	5.16%
2007.4	10.43%	4.53%	5.90%
2008.1	10.15%	4.34%	5.81%
2008.2	10.54%	4.57%	5.97%
2008.3	10.38%	4.44%	5.95%
2008.4	10.39%	3.49%	6.89%
2009.1	10.45%	3.62%	6.83%
2009.2	10.58%	4.23%	6.35%
2009.3	10.46%	4.18%	6.28%
2009.4	10.54%	4.35%	6.19%
2010.1	10.45%	4.59%	5.86%
2010.2	10.08%	4.20%	5.87%
2010.3	10.29%	3.73%	6.56%
2010.4	10.34%	4.14%	6.20%
2011.1	9.96%	4.53%	5.44%
2011.2	10.12%	4.33%	5.79%
2011.3	10.36%	3.54%	6.82%
2011.4	10.34%	3.03%	7.32%
2012.1	10.30%	3.12%	7.18%
2012.2	9.92%	2.84%	7.08%
2012.3	9.78%	2.68%	7.10%
2012.4	10.07%	2.87%	7.20%
2013.1	9.77%	3.12%	6.65%
2013.2	9.84%	3.22%	6.62%
2013.3	9.83%	3.67%	6.16%
2013.4	9.82%	3.81%	6.02%
2014.1	9.57%	3.58%	5.99%
2014.2	9.83%	3.38%	6.45%
2014.3	9.79%	3.20%	6.59%
2014.4	9.78%	2.90%	6.88%
2015.1	9.67%	2.41%	7.26%
AVERAGE	10.84%	5.18%	5.66%
MEDIAN	10.75%	5.01%	5.79%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.85873
R Square	0.73741
Adjusted R Square	0.73453
Standard Error	0.00470
Observations	93

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.00565	0.00565	255.54873	0.00000
Residual	91	0.00201	0.00002		
Total	92	0.00766			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0863	0.00192	44.98	0.00000	0.08250	0.09012	0.08250	0.09012
30-year U.S. Treasury Bond	-0.5731	0.03585	-15.99	0.00000	-0.64428	-0.50186	-0.64428	-0.50186

	[7] U.S. Govt. 30-year Treasury	[8] Risk Premium	[9] ROE
Current 30-Day Average [4]	2.50%	7.20%	9.70%
Blue Chip Consensus Forecast (Q1 2015-Q2 2016) [5]	3.20%	6.80%	10.00%
Blue Chip Consensus Forecast (2016-2020) [6]	4.90%	5.82%	10.72%
MEAN			10.14%

Notes:
[1] Source: Regulatory Research Associates
[2] Source: Bloomberg Professional, quarterly bond yields are the average of the last trading day of each month in the quarter
[3] Equals Column [1] – Column [2]
[4] Source: Bloomberg Professional
[5] Source: Blue Chip Financial Forecasts, Vol. 34, No. 2, February 1, 2015, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 33, No. 12, December 1, 2014, at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.086308 + (-0.573069 x Column [7])
[9] Equals Column [7] + Column [8]

Exhibit AEB-7

COMPARISON OF UNS ELECTRIC AND PROXY GROUP COMPANIES
CAPITAL COST RECOVERY MECHANISMS [1]

Parent Company	Operating Subsidiaries	States of Operation [2]	Capital Tracking Mechanism [3]
ALLETE, Inc.	Minnesota Power	Minnesota	Y
	Superior Water, Light and Power Company	Wisconsin [4]	N
American Electric Power Company, Inc.	AEP Texas Central Company	Texas	Y
	AEP Texas North Company	Texas	Y
	Appalachian Power Company	Virginia	Y
	Appalachian Power Company	West Virginia	Y
	Indiana Michigan Power Company	Indiana	Y
	Indiana Michigan Power Company	Michigan	N
	Kentucky Power Company	Kentucky	Y
	Kingsport Power Company	Tennessee	N
	Ohio Power Company	Ohio	Y
	Public Service Company of Oklahoma	Oklahoma	Y
	Southwestern Electric Power Company	Arkansas	Y
	Southwestern Electric Power Company	Louisiana	N
	Southwestern Electric Power Company	Texas	Y
	Wheeling Power Company	West Virginia	Y
Duke Energy Corporation	Duke Energy Carolinas, LLC	North Carolina	N
	Duke Energy Carolinas, LLC	South Carolina	N
	Duke Energy Florida, Inc.	Florida	Y
	Duke Energy Indiana, Inc.	Indiana	Y
	Duke Energy Kentucky, Inc.	Kentucky	N
	Duke Energy Ohio, Inc.	Ohio	N
	Duke Energy Progress, Inc.	North Carolina	N
	Duke Energy Progress, Inc.	South Carolina	N
Empire District Electric Company	Empire District Electric Company	Arkansas [5]	Y
	Empire District Electric Company	Kansas	N
	Empire District Electric Company	Missouri	N
	Empire District Electric Company	Oklahoma [6]	Y
Eversource Energy	Connecticut Light and Power Company	Connecticut	Y
	NSTAR Electric Company	Massachusetts	Y
	Public Service Company of New Hampshire	New Hampshire	Y
	Western Massachusetts Electric Company	Massachusetts	Y
Great Plains Energy Inc.	Kansas City Power & Light Company	Kansas	N
	Kansas City Power & Light Company	Missouri	N
	KCP&L Greater Missouri Operations Company	Missouri	N
IDACORP, Inc.	Idaho Power Co.	Idaho	N
	Idaho Power Co.	Oregon	N
Otter Tail Corporation	Otter Tail Power Company	Minnesota	Y
	Otter Tail Power Company	North Dakota	Y
	Otter Tail Power Company	South Dakota [7]	Y
Pinnacle West Capital Corporation	Arizona Public Service Company	Arizona	Y
PNM Resources, Inc.	Public Service Company of New Mexico	New Mexico	N
	Texas-New Mexico Power Company	Texas	Y
Portland General Electric Company	Portland General Electric Company	Oregon	N
Southern Company	Alabama Power Company	Alabama	Y
	Georgia Power Company	Georgia	Y
	Gulf Power Company	Florida	Y
	Mississippi Power Company	Mississippi	Y
Westar Energy, Inc.	Kansas Gas and Electric Company	Kansas	Y
	Westar Energy (KPL)	Kansas	Y
Proxy Group Average			62.00%
Fortis Inc.	UNS Electric		Y

Notes
[1] Source: Regulatory Research Associates, Regulatory Focus, Adjustment Clauses - A State-by-State Overview, July 1, 2014.
[2] Electric Operations Only
[3] Capital costs include: transmission cost recovery, environmental compliance costs, and capital tracking mechanisms.
[4] Superior Water, Light and Power Company Tariff
[5] Empire District Electric Company Arkansas Tariff
[6] Empire District Electric Company Oklahoma Tariff
[7] Otter Tail Power Company South Dakota Tariff

Exhibit AEB-8

SIZE PREMIUM CALCULATION

Proxy Group Market Capitalization and Market-to-Book Ratio

Company	Ticker	[1] Market Capitalization ($ Billions)	[2] Market-to-Book Ratio
ALLETE, Inc.	ALE	2.53	1.60
American Electric Power Company, Inc.	AEP	29.82	1.77
Duke Energy Corporation	DUK	59.46	1.45
Empire District Electric Company	EDE	1.23	1.57
Eversource Energy	ES	17.17	1.72
Great Plains Energy Inc.	GXP	4.38	1.22
IDACORP, Inc.	IDA	3.31	1.69
Otter Tail Corporation	OTTR	1.17	2.07
Pinnacle West Capital Corporation	PNW	7.58	1.74
PNM Resources, Inc.	PNM	2.36	1.37
Portland General Electric Company	POR	3.02	1.58
Southern Company	SO	44.15	2.23
Westar Energy, Inc.	WR	5.43	1.66
MEAN		$ 13.969	1.67
MEDIAN		$ 4.380	1.66

UNS Electric, Inc.	
Capitalization ($ Millions) [3]	$ 359.5
Common Equity Ratio [4]	52.83%
Capitalitalization x Common Equity Ratio [5]	189.9
Implied Market Capitalization [6]	315.1
As a percent of Proxy Group Median Market Capitalization	7.19%

Ibbotson SBBI 2014 Classic Yearbook -- Size Premium

Breakdown of Deciles 1-10	[7] Market Capitalization of Largest Company ($ millions)	[8] Size Premium
1-Largest	428,699.798	-0.33%
2	21,739.006	0.80%
3	9,196.480	0.93%
4	5,569.840	1.19%
5	3,573.079	1.72%
6	2,431.229	1.75%
7	1,621.792	1.75%
8	1,055.320	2.48%
9	632.770	2.76%
10-Smallest	338.829	6.01%
UNS Electric, Inc. Implied Market Capitalization	315.072	6.01%
Proxy Group Median Market Capitalization	4,379.585	1.19%
Size Premium [9]		4.82%

Notes:
[1] Source: Bloomberg Professional; equals 30-day average as of February 27th, 2015.
[2] Source: Bloomberg Professional; equals 30-day average as of February 27th, 2015.
[3] Source: UNS Company Data
[4] Source: UNS Company Data
[5] Equals [3] x [4]
[6] Equals [5] x proxy group median market-to-book ratio
[7] Source: Morningstar, Inc., Ibbotson SBBI 2014 Classic Yearbook, at Table 7-5.
[8] Source: Morningstar, Inc., Ibbotson SBBI 2014 Classic Yearbook, at Table 7-6.
[9] Equals 6.01% - 1.19%

Exhibit AEB-9

COMPARISON OF UNS ELECTRIC AND PROXY GROUP COMPANIES
S&P JURISDICTIONAL RANKINGS

		[1]	[2]
		S&P	
		Rank	Numeric Rank
ALLETE, Inc.	Minnesota	Strong/Adequate (14)	14
	Wisconsin	Strong (2)	2
American Electric Power Company, Inc.	Arkansas	Strong/Adequate (28)	28
	Indiana	Strong/Adequate (27)	27
	Kentucky	Strong (9)	9
	Louisiana	Strong/Adequate (13)	13
	Michigan	Strong (4)	4
	Ohio	Strong/Adequate (36)	36
	Oklahoma	Strong/Adequate (15)	15
	Tennessee	Strong/Adequate (22)	22
	Texas (PUC)	Strong/Adequate (44)	44
	Virginia	Strong/Adequate (19)	19
	West Virginia	Strong/Adequate (39)	39
Duke Energy Corporation	Florida	Strong (3)	3
	Indiana	Strong/Adequate (27)	27
	Kentucky	Strong (9)	9
	North Carolina	Strong (8)	8
	Ohio	Strong/Adequate (36)	36
	South Carolina	Strong (7)	7
Empire District Electric Company	Arkansas	Strong/Adequate (28)	28
	Kansas	Strong/Adequate (21)	21
	Oklahoma	Strong/Adequate (15)	15
	Missouri	Strong/Adequate (43)	43
Eversource Energy	Connecticut	Strong/Adequate (45)	45
	Massachusetts	Strong/Adequate (37)	37
	New Hampshire	Strong/Adequate (50)	50
Great Plains Energy Inc.	Kansas	Strong/Adequate (21)	21
	Missouri	Strong/Adequate (43)	43
IDACORP, Inc.	Idaho	Strong/Adequate (32)	32
	Oregon	Strong/Adequate (20)	20
Otter Tail Corporation	Minnesota	Strong/Adequate (14)	14
	North Dakota	Strong/Adequate (31)	31
	South Dakota	Strong/Adequate (29)	29
Pinnacle West Capital Corporation	Arizona	Strong/Adequate (30)	30
PNM Resources, Inc.	New Mexico	Strong/Adequate (49)	49
	Texas (PUC)	Strong/Adequate (44)	44
Portland General Electric Company	Oregon	Strong/Adequate (20)	20
Southern Company	Alabama	Strong (5)	5
	Florida	Strong (3)	3
	Georgia	Strong/Adequate (12)	12
	Mississippi	Adequate (53)	53
Westar Energy, Inc.	Kansas	Strong/Adequate (21)	21
Proxy Group Average		Strong/Adequate (24) / Strong/Adequate (25)	24.48
UNS Electric	Arizona	Strong/Adequate (30)	30

Notes
[1] Source: Utility Regulatory Assessments for U.S. Investor-Owned Utilities, Standard and Poor's Ratings Services, January 7, 2014

Exhibit AEB-10

CAPITAL STRUCTURE ANALYSIS

COMMON EQUITY RATIO

Company	Ticker	2014Q3	2014Q2	2014Q1	2013Q4	2013Q3	2013Q2	2013Q1	2012Q4	Average
ALLETE, Inc.	ALE	56.18%	55.83%	56.79%	56.37%	58.08%	57.90%	58.79%	57.98%	57.24%
American Electric Power Company, Inc.	AEP	52.27%	52.31%	52.34%	52.36%	53.51%	53.61%	53.71%	53.15%	52.91%
Duke Energy Corporation	DUK	56.60%	56.03%	55.25%	56.09%	55.83%	56.41%	55.95%	55.43%	55.95%
Empire District Electric Company	EDE	53.31%	52.82%	52.73%	52.30%	52.37%	51.52%	53.36%	53.15%	52.70%
Eversource Energy	ES	53.44%	52.05%	51.25%	52.89%	54.51%	53.07%	52.87%	53.48%	52.94%
Great Plains Energy Inc.	GXP	53.42%	52.67%	52.56%	52.49%	52.51%	52.94%	53.35%	55.12%	53.13%
IDACORP, Inc.	IDA	52.92%	52.03%	51.72%	51.61%	50.51%	49.74%	51.66%	51.39%	51.45%
Otter Tail Corporation	OTTR	49.32%	47.60%	47.20%	53.72%	52.37%	52.35%	52.69%	51.98%	50.90%
Pinnacle West Capital Corporation	PNW	58.43%	57.32%	55.67%	57.39%	57.62%	55.94%	55.84%	56.46%	56.83%
PNM Resources, Inc.	PNM	52.96%	52.74%	53.49%	54.17%	54.36%	54.24%	55.55%	55.30%	54.10%
Portland General Electric Company	POR	44.86%	46.64%	49.21%	48.70%	50.43%	50.37%	51.78%	51.37%	49.17%
Southern Company	SO	47.81%	48.61%	48.44%	50.12%	48.24%	46.25%	46.59%	48.25%	48.04%
Westar Energy, Inc.	WR	65.95%	66.62%	63.45%	63.22%	61.28%	61.87%	60.32%	61.71%	63.05%
MEAN		53.65%	53.33%	53.08%	53.96%	53.97%	53.56%	54.03%	54.21%	53.72%
MEDIAN		53.31%	52.67%	52.56%	52.89%	53.51%	53.07%	53.36%	53.48%	52.94%
LOW		44.86%	46.64%	47.20%	48.70%	48.24%	46.25%	46.59%	48.25%	48.04%
HIGH		65.95%	66.62%	63.45%	63.22%	61.28%	61.87%	60.32%	61.71%	63.05%

COMMON EQUITY RATIO - ELECTRIC UTILITY OPERATING COMPANIES

Company	Ticker	2014Q3	2014Q2	2014Q1	2013Q4	2013Q3	2013Q2	2013Q1	2012Q4	Average
ALLETE (Minnesota Power)	ALE	53.98%	53.01%	55.16%	55.93%	54.90%	54.13%	56.09%	55.30%	54.81%
Superior Water, Light and Power Company	ALE	58.39%	58.65%	58.42%	56.81%	61.25%	61.67%	61.48%	60.66%	59.67%
AEP Texas Central Company	AEP	43.93%	43.18%	47.56%	46.75%	46.62%	47.89%	51.26%	50.56%	47.22%
AEP Texas North Company	AEP	47.06%	46.79%	46.82%	46.68%	46.03%	50.34%	49.89%	47.59%	47.65%
Appalachian Power Company	AEP	46.29%	46.00%	44.13%	43.52%	47.39%	45.29%	45.37%	45.19%	45.40%
Indiana Michigan Power Company	AEP	51.45%	51.39%	51.63%	50.80%	48.27%	47.77%	46.88%	49.59%	49.72%
Kentucky Power Company	AEP	46.25%	48.23%	50.30%	52.83%	46.02%	47.18%	47.17%	46.62%	48.08%
Kingsport Power Company	AEP	60.55%	60.91%	58.88%	60.85%	60.73%	60.33%	60.84%	59.96%	60.38%
Ohio Power Company	AEP	46.03%	44.79%	42.54%	39.71%	57.01%	56.06%	56.09%	53.77%	49.50%
Public Service Company of Oklahoma	AEP	49.43%	48.30%	47.51%	48.51%	50.46%	49.49%	49.09%	49.10%	48.99%
Southwestern Electric Power Company	AEP	50.60%	51.26%	51.18%	51.21%	50.22%	50.52%	50.54%	50.80%	50.79%
Wheeling Power Company	AEP	81.14%	82.27%	82.89%	82.79%	82.32%	81.26%	79.99%	78.28%	81.37%
Duke Energy Carolinas, LLC	DUK	56.60%	55.90%	55.56%	55.18%	53.80%	53.57%	53.74%	53.13%	54.69%
Duke Energy Florida, Inc.	DUK	50.98%	49.96%	49.22%	50.47%	50.61%	49.57%	51.06%	48.33%	50.02%
Duke Energy Indiana, Inc.	DUK	49.88%	50.69%	51.57%	50.85%	50.31%	51.11%	50.57%	49.97%	50.62%
Duke Energy Kentucky, Inc.	DUK	54.78%	54.36%	54.16%	53.23%	52.56%	54.56%	54.13%	52.90%	53.83%
Duke Energy Ohio, Inc.	DUK	76.40%	74.55%	70.11%	74.27%	74.25%	79.06%	75.95%	76.02%	75.08%
Duke Energy Progress, Inc.	DUK	50.99%	50.75%	50.85%	52.54%	53.43%	50.62%	50.25%	52.25%	51.46%
Empire District Electric Company	EDE	53.31%	52.82%	52.73%	52.30%	52.37%	51.52%	53.36%	53.15%	52.70%
Connecticut Light and Power Company	ES	52.72%	50.52%	52.33%	52.01%	51.43%	49.95%	49.67%	53.33%	51.50%
NSTAR Electric Company	ES	57.17%	55.95%	51.45%	57.35%	56.78%	55.65%	58.53%	58.01%	56.36%
Public Service Company of New Hampshire	ES	53.92%	52.44%	52.27%	51.90%	55.78%	55.52%	52.41%	52.12%	53.29%
Western Massachusetts Electric Company	ES	49.97%	49.29%	48.96%	50.31%	54.03%	51.15%	50.85%	50.45%	50.63%
Kansas City Power & Light Company	GXP	49.54%	48.67%	48.46%	48.46%	48.57%	47.70%	48.68%	52.37%	49.06%
KCP&L Greater Missouri Operations Company	GXP	57.30%	56.68%	56.66%	56.52%	56.46%	58.18%	58.02%	57.87%	57.21%
Idaho Power Co.	IDA	52.92%	52.03%	51.72%	51.61%	50.51%	49.74%	51.66%	51.39%	51.45%
Otter Tail Power Company	OTTR	49.32%	47.60%	47.20%	53.72%	52.37%	52.35%	52.69%	51.98%	50.90%
Arizona Public Service Company	PNW	58.43%	57.32%	55.67%	57.39%	57.62%	55.94%	55.84%	56.46%	56.83%
Public Service Company of New Mexico	PNM	47.43%	47.14%	46.70%	48.39%	49.79%	50.07%	51.10%	50.78%	48.93%
Texas-New Mexico Power Company	PNM	58.49%	58.35%	60.27%	59.95%	58.92%	58.41%	60.00%	59.82%	59.27%
Portland General Electric Company	POR	44.86%	46.64%	49.21%	48.70%	50.43%	50.37%	51.78%	51.37%	49.17%
Alabama Power Company	SO	46.48%	47.34%	47.15%	46.87%	47.52%	46.91%	46.67%	46.59%	46.94%
Georgia Power Company	SO	51.08%	50.42%	50.10%	52.73%	50.99%	49.21%	48.98%	49.06%	50.32%
Gulf Power Company	SO	47.60%	50.95%	51.11%	49.97%	49.75%	47.68%	49.33%	48.62%	49.37%
Mississippi Power Company	SO	46.07%	45.72%	45.39%	50.90%	44.71%	41.20%	41.36%	48.71%	45.51%
Kansas Gas and Electric Company	WR	72.65%	77.67%	69.73%	69.54%	65.91%	65.08%	62.22%	62.02%	68.10%
Westar Energy (KPL)	WR	59.26%	55.58%	57.17%	56.90%	56.66%	58.66%	58.41%	61.40%	58.00%

Source: SNL Financial

CAPITAL STRUCTURE ANALYSIS

LONG-TERM DEBT RATIO

Company	Ticker	2014Q3	2014Q2	2014Q1	2013Q4	2013Q3	2013Q2	2013Q1	2012Q4	Average
ALLETE, Inc.	ALE	43.82%	44.17%	43.21%	43.63%	41.92%	42.10%	41.21%	42.02%	42.76%
American Electric Power Company, Inc.	AEP	47.73%	47.69%	47.66%	47.64%	46.49%	46.39%	46.29%	46.85%	47.09%
Duke Energy Corporation	DUK	43.40%	43.97%	44.75%	43.91%	44.17%	43.59%	44.05%	44.57%	44.05%
Empire District Electric Company	EDE	46.69%	47.18%	47.27%	47.70%	47.63%	48.48%	46.64%	46.85%	47.30%
Eversource Energy	ES	46.56%	47.95%	48.75%	47.11%	45.49%	46.93%	47.13%	46.52%	47.06%
Great Plains Energy Inc.	GXP	46.58%	47.33%	47.44%	47.51%	47.49%	47.06%	46.65%	44.88%	46.87%
IDACORP, Inc.	IDA	47.08%	47.97%	48.28%	48.39%	49.49%	50.26%	48.34%	48.61%	48.55%
Otter Tail Corporation	OTTR	50.68%	52.40%	52.80%	46.28%	47.63%	47.65%	47.31%	48.02%	49.10%
Pinnacle West Capital Corporation	PNW	41.57%	42.68%	44.33%	42.61%	42.38%	44.06%	44.16%	43.54%	43.17%
PNM Resources, Inc.	PNM	47.04%	47.26%	46.51%	45.83%	45.64%	45.76%	44.45%	44.70%	45.90%
Portland General Electric Company	POR	55.14%	53.36%	50.79%	51.30%	49.57%	49.63%	48.22%	48.63%	50.83%
Southern Company	SO	52.19%	51.39%	51.56%	49.88%	51.76%	53.75%	53.41%	51.75%	51.96%
Westar Energy, Inc.	WR	34.05%	33.38%	36.55%	36.78%	38.72%	38.13%	39.68%	38.29%	36.95%
MEAN		46.35%	46.67%	46.92%	46.04%	46.03%	46.44%	45.97%	45.79%	46.28%
MEDIAN		46.69%	47.33%	47.44%	47.11%	46.49%	46.93%	46.64%	46.52%	47.06%
LOW		34.05%	33.38%	36.55%	36.78%	38.72%	38.13%	39.68%	38.29%	36.95%
HIGH		55.14%	53.36%	52.80%	51.30%	51.76%	53.75%	53.41%	51.75%	51.96%

LONG-TERM DEBT RATIO - ELECTRIC UTILITY OPERATING COMPANIES

Company	Ticker	2014Q3	2014Q2	2014Q1	2013Q4	2013Q3	2013Q2	2013Q1	2012Q4	Average
ALLETE (Minnesota Power)	ALE	46.02%	46.99%	44.84%	44.07%	45.10%	45.87%	43.91%	44.70%	45.19%
Superior Water, Light and Power Company	ALE	41.61%	41.35%	41.58%	43.19%	38.75%	38.33%	38.52%	39.34%	40.33%
AEP Texas Central Company	AEP	56.07%	56.82%	52.44%	53.25%	53.38%	52.11%	48.74%	49.44%	52.78%
AEP Texas North Company	AEP	52.94%	53.21%	53.18%	53.32%	53.97%	49.66%	50.11%	52.41%	52.35%
Appalachian Power Company	AEP	53.71%	54.00%	55.87%	56.48%	52.61%	54.71%	54.63%	54.81%	54.60%
Indiana Michigan Power Company	AEP	48.55%	48.61%	48.37%	49.20%	51.73%	52.23%	53.12%	50.41%	50.28%
Kentucky Power Company	AEP	53.75%	51.77%	49.70%	47.17%	53.98%	52.82%	52.83%	53.38%	51.92%
Kingsport Power Company	AEP	39.45%	39.09%	41.12%	39.15%	39.27%	39.67%	39.16%	40.04%	39.62%
Ohio Power Company	AEP	53.97%	55.21%	57.46%	60.29%	42.99%	43.94%	43.91%	46.23%	50.50%
Public Service Company of Oklahoma	AEP	50.57%	51.70%	52.49%	51.49%	49.54%	50.51%	50.91%	50.90%	51.01%
Southwestern Electric Power Company	AEP	49.40%	48.74%	48.82%	48.79%	49.78%	49.48%	49.46%	49.20%	49.21%
Wheeling Power Company	AEP	18.86%	17.73%	17.11%	17.21%	17.68%	18.74%	20.01%	21.72%	18.63%
Duke Energy Carolinas, LLC	DUK	43.40%	44.10%	44.44%	44.82%	46.20%	46.43%	46.26%	46.87%	45.31%
Duke Energy Florida, Inc.	DUK	49.02%	50.04%	50.78%	49.53%	49.39%	50.43%	48.94%	51.67%	49.98%
Duke Energy Indiana, Inc.	DUK	50.12%	49.31%	48.43%	49.15%	49.69%	48.89%	49.43%	50.03%	49.38%
Duke Energy Kentucky, Inc.	DUK	45.22%	45.64%	45.84%	46.77%	47.44%	45.44%	45.87%	47.10%	46.17%
Duke Energy Ohio, Inc.	DUK	23.60%	25.45%	29.89%	25.73%	25.75%	20.94%	24.05%	23.98%	24.92%
Duke Energy Progress, Inc.	DUK	49.01%	49.25%	49.15%	47.46%	46.57%	49.38%	49.75%	47.75%	48.54%
Empire District Electric Company	EDE	46.69%	47.18%	47.27%	47.70%	47.63%	48.48%	46.64%	46.85%	47.30%
Connecticut Light and Power Company	ES	47.28%	49.48%	47.67%	47.99%	48.57%	50.05%	50.33%	46.67%	48.50%
NSTAR Electric Company	ES	42.83%	44.05%	48.55%	42.65%	43.22%	44.35%	41.47%	41.99%	43.64%
Public Service Company of New Hampshire	ES	46.08%	47.56%	47.73%	48.10%	44.22%	44.48%	47.59%	47.88%	46.71%
Western Massachusetts Electric Company	ES	50.03%	50.71%	51.04%	49.69%	45.97%	48.85%	49.15%	49.55%	49.37%
Kansas City Power & Light Company	GXP	50.46%	51.33%	51.54%	51.54%	51.43%	52.30%	51.32%	47.63%	50.94%
KCP&L Greater Missouri Operations Company	GXP	42.70%	43.32%	43.34%	43.48%	43.54%	41.82%	41.98%	42.13%	42.79%
Idaho Power Co.	IDA	47.08%	47.97%	48.28%	48.39%	49.49%	50.26%	48.34%	48.61%	48.55%
Otter Tail Power Company	OTTR	50.68%	52.40%	52.80%	46.28%	47.63%	47.65%	47.31%	48.02%	49.10%
Arizona Public Service Company	PNW	41.57%	42.68%	44.33%	42.61%	42.38%	44.06%	44.16%	43.54%	43.17%
Public Service Company of New Mexico	PNM	52.57%	52.86%	53.30%	51.61%	50.21%	49.93%	48.90%	49.22%	51.07%
Texas-New Mexico Power Company	PNM	41.51%	41.65%	39.73%	40.05%	41.08%	41.59%	40.00%	40.18%	40.73%
Portland General Electric Company	POR	55.14%	53.36%	50.79%	51.30%	49.57%	49.63%	48.22%	48.63%	50.83%
Alabama Power Company	SO	53.52%	52.66%	52.85%	53.13%	52.48%	53.09%	53.33%	53.41%	53.06%
Georgia Power Company	SO	48.92%	49.58%	49.90%	47.27%	49.01%	50.79%	51.02%	50.94%	49.68%
Gulf Power Company	SO	52.40%	49.05%	48.89%	50.03%	50.25%	52.32%	50.67%	51.38%	50.63%
Mississippi Power Company	SO	53.93%	54.28%	54.61%	49.10%	55.29%	58.80%	58.64%	51.29%	54.49%
Kansas Gas and Electric Company	WR	27.35%	22.33%	30.27%	30.46%	34.09%	34.92%	37.78%	37.98%	31.90%
Westar Energy (KPL)	WR	40.74%	44.42%	42.83%	43.10%	43.34%	41.34%	41.59%	38.60%	42.00%

Source: SNL Financial

Exhibit AEB-11

UNS ELECTRIC
FAIR VALUE RATE OF RETURN
ARIZONA STAFF METHODOLOGY

	Amount ($M)	Weighting	Weighted Amount ($M)	
Original Cost Rate Base (OCRB)	$ 272.0	50.00%	$ 136.0	[1]
Replacement Cost New, Depreciated Rate Base (RCND)	$ 439.4	50.00%	219.7	[2]
Fair Value Rate Base (FVRB)			355.7	[3]
Appreciation Above OCRB			$ 83.7	[4]
FVRB / OCRB Multiple			1.31	

Capital	Amount ($M)	Percent	Cost Rate		Weighted Cost Rate	
Long-Term Debt	$ 128.3	36.07%	4.66%	[5]	1.68%	
Common Equity	143.7	40.40%	10.35%	[6]	4.18%	
Capital Financing OCRB	$ 272.0	76.47%			5.86%	
Appreciation Above OCRB Not Recognized on Utility's Books	83.7	23.53%	1.50%		0.35%	
Total	$ 355.7	100.00%			6.22%	[7]

[1] Direct Testimony of Dallas J. Dukes, Schedule B-1
[2] Direct Testimony of Dallas J. Dukes, Schedule B-1
[3] Equals [1] + [2]
[4] Equals [3] − OCRB
[5] Schedule D-1
[6] Equals Recommended ROE on OCRB
[7] Capital Financing OCRB + Return on Fair Value Increment

CALCULATION OF INFLATION RATE

Step 1	
Consumer Price Index (YoY % Change) [1]	
2016-2020	2.40%
2021-2025	2.30%
Average	2.35%
Consumer Price Index (All-Urban) [2]	
2014	2.37
2025	2.90
Compound Annual Growth Rate	1.85%
GDP Chain-type Price Index (2005=1.000) [2]	
2014	1.19
2025	1.42
Compound Annual Growth Rate	1.61%
Average Inflation Forecast	**1.94%**
Step 2	
Nominal U.S. Treasury Bond Yield, 30-year [1]	
2016-2020	4.90%
2021-2025	5.10%
	5.00%
Real Risk-Free Rate [3]	**3.01%**
50.0% of Real Risk-Free Rate [4]	**1.50%**

Notes:
[1] Blue Chip Financial Forecasts, Vol. 33, No. 12, December 1, 2014, at 14.
[2] Energy Information Administration, Annual Energy Outlook 2014, Table 20
[3] Equals (5.00% + 1) / (1 + 1.94%) − 1
[4] Equals [3] x 50.0%

Exhibit AEB-12

Comparable Transactions Analysis
Calculation of Transaction Premium over Corporate Value

Target	Buyer	[1] Date Announced	[2] Target Book Value Per Share	[3] Target Deal Value Per Share	[4] Premium to Equity	[5] Target Equity Ratio	[6] Transaction Premium to Corporate Value	[7] Implied UNSE Valuation ($M)
UIL Holdings Corporation	Iberdrola, S.A.	02/25/15	$24.07	$52.75	119.20%	46.10%	54.95%	$421.5
Hawaiian Electric Industries, Inc.	NextEra Energy, Inc.	12/03/14	$17.56	$33.50	90.73%	59.71%	54.17%	$419.4
Cleco Corporation	Investor group	10/20/14	$27.14	$55.37	103.99%	55.66%	57.88%	$429.4
Integrys Energy Group, Inc.	Wisconsin Energy Corporation	06/23/14	$42.17	$71.47	69.48%	56.42%	39.20%	$378.7
Pepco Holdings, Inc.	Exelon Corporation	04/30/14	$17.28	$27.25	57.73%	52.88%	30.53%	$355.1
UNS Energy Corporation	Fortis Inc.	12/11/13	$22.75	$60.25	164.83%	61.58%	101.50%	$548.1
NV Energy, Inc.	Berkshire Hathaway Inc.	05/29/13	$15.05	$23.75	57.84%	46.99%	27.18%	$345.9
CH Energy Group, Inc.	Fortis Inc.	02/21/12	$33.72	$65.00	92.77%	55.96%	51.92%	$413.2
Central Vermont Public Service Corporation	Gaz Métro LP	06/23/11	$20.59	$35.25	71.20%	61.29%	43.64%	$390.7
Constellation Energy Group Inc.	Exelon Corporation	04/28/11	$39.65	$38.59	-2.68%	65.30%	-1.75%	$267.3
DPL Inc.	AES Corporation	04/19/11	$10.52	$30.00	185.18%	63.13%	116.90%	$590.0
Progress Energy Inc.	Duke Energy Corporation	01/10/11	$34.21	$46.47	35.86%	46.68%	16.74%	$317.5
NSTAR	Northeast Utilities	10/18/10	$18.60	$40.28	116.51%	51.31%	59.79%	$434.6
Allegheny Energy, Inc.	FirstEnergy Corporation	02/11/10	$18.36	$27.65	50.62%	42.53%	21.53%	$330.6
Puget Energy, Inc.	Investor Consortium	10/25/07	$18.45	$30.00	62.63%	50.35%	31.54%	$357.8
Energy East Corporation	Iberdrola, S.A.	06/25/07	$20.21	$28.50	41.01%	48.37%	19.83%	$326.0
Aquila, Inc.	Great Plains Energy, Inc.	02/06/07	$3.49	$4.54	30.18%	48.89%	14.76%	$312.2
Duquesne Light Holdings, Inc	Macquarie Consortium	07/05/06	$8.41	$20.00	137.82%	46.83%	64.55%	$447.6
Green Mountain Power Corporation	Gaz Métro LP	06/21/06	$22.79	$35.00	53.60%	61.71%	33.08%	$362.0
KeySpan Corp.	National Grid Group PLC	02/25/06	$25.60	$42.00	64.05%	56.78%	36.37%	$370.9
Cinergy Corp.	Duke Energy Corporation	05/08/05	$22.71	$45.80	101.69%	55.23%	56.16%	$424.8
RGS Energy Group, Inc.	Energy East Corporation	02/16/01	$22.19	$39.50	78.04%	55.15%	43.04%	$389.1
Conectiv	Potomac Electric Power Company	02/12/01	$13.10	$25.00	90.91%	54.41%	49.46%	$406.6
Montana Power Company	NorthWestern Corporation	09/28/00	$9.86	$10.50	6.53%	77.59%	5.06%	$285.8
Niagara Mohawk Holdings, Inc.	National Grid Group PLC	09/04/00	$16.90	$19.00	12.39%	43.41%	5.38%	$286.6
GPU, Inc.	FirstEnergy Corporation	08/08/00	$27.01	$36.50	35.12%	54.35%	19.09%	$323.9
IPALCO Enterprises, Inc.	AES Corporation	07/15/00	$7.76	$25.00	222.03%	49.21%	109.27%	$569.2
Bangor Hydro-Electric Company	NS Power Holdings Inc.	06/29/00	$18.34	$26.50	44.46%	46.73%	20.77%	$328.5
LG&E Energy Corp.	Powergen PLC	02/27/00	$8.80	$24.85	182.35%	63.37%	115.56%	$586.3
MidAmerican Energy Holdings Company	Investor group	10/24/99	$15.59	$35.05	124.81%	20.58%	25.69%	$341.9
Unicom Corporation	PECO Energy Company	09/22/99	$23.51	$34.40	46.36%	49.01%	22.72%	$333.8
Florida Progress Corporation	Carolina Power & Light Company	08/22/99	$19.70	$54.00	174.08%	51.35%	89.39%	$515.2
CMP Group, Inc.	Energy East Corporation	06/14/99	$16.79	$29.50	75.72%	78.19%	59.20%	$433.1
TNP Enterprises, Inc.	Investor Group	05/24/99	$23.21	$44.00	89.59%	40.00%	35.84%	$369.5
Eastern Utilities Associates	National Grid Group PLC	02/01/99	$18.29	$31.46	72.05%	61.42%	44.25%	$392.4
New England Electric System	National Grid Group PLC	12/11/98	$29.30	$53.75	83.48%	62.49%	52.16%	$413.9
PacifiCorp	Scottish Power PLC	12/06/98	$13.47	$25.13	86.56%	54.51%	47.19%	$400.4
Commonwealth Energy System	BEC Energy	12/05/98	$20.75	$44.10	112.58%	54.79%	61.68%	$439.8
CILCORP Inc	AES Corporation	11/23/98	$26.24	$65.00	147.71%	62.91%	92.92%	$524.8
MidAmerican Energy Holdings Company	CalEnergy Company, Inc.	08/11/98	$12.99	$27.15	109.07%	25.20%	27.49%	$346.8
Orange and Rockland Utilities, Inc.	Consolidated Edison, Inc.	05/10/98	$27.92	$58.50	109.52%	60.21%	65.94%	$451.4
Nevada Power Company	Sierra Pacific Resources	04/29/98	$16.33	$26.00	59.20%	52.88%	31.30%	$357.2
KU Energy Corporation	LG&E Energy Corporation	05/20/97	$17.29	$40.71	135.48%	56.38%	76.39%	$479.8

	[6]	[7]
Min:	**-1.75%**	**$267.3**
Max:	**116.90%**	**$590.0**
Mean:	**47.22%**	**$400.4**
Median:	**43.64%**	**$390.7**
Std. Dev.:	**29.15%**	**$79.3**
Count:	**43**	**43**

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional
[3] Source: SEC Filings
[4] Equals ([3] − [2]) / [2]
[5] Source: Bloomberg Professional
[6] Equals [4] x [5]
[7] Equals UNS Electric's OCRB x (1 + [6])

Direct Testimony of
Ronald E. White

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.

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[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

DISTRIBUTION

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)
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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.

	Accrual Rate			2015 Annualized Accrual		
Function	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	$ -
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Table 2. Gila River Power Station

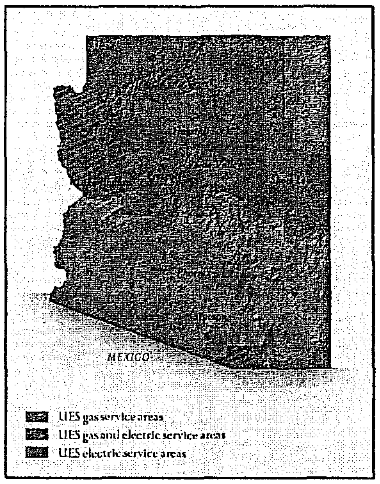
The composite accrual rate recommended for Gila River is 2.58 percent. The current equivalent rate is 2.29 percent. The recommended change in the composite rate is an increase of 0.29 percentage points.

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) Investment	Net Salvage	Total	Proposed (at 12/31/2013) 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. Statement A

Component Accrual Rates

Current: BG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

		Current (at 12/31/2013)			Proposed (at 12/31/2013)		
	Account Description	Investment	Net Salvage	Total	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.

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
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 2014 Annualized Accrual Net Salvage	Current 2014 Annualized Accrual Total	Proposed 2014 Annualized Accrual Investment	Proposed 2014 Annualized Accrual Net Salvage	Proposed 2014 Annualized Accrual 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.

Statement B

Component Accruals
Current: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

	Account Description	12/31/13 Investment	Current 2014 Annualized Accrual Investment	Current 2014 Annualized Accrual Net Salvage	Current 2014 Annualized Accrual Total	Proposed 2014 Annualized Accrual Investment	Proposed 2014 Annualized Accrual Net Salvage	Proposed 2014 Annualized Accrual Total	Difference
	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 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
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 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
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
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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
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
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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
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.
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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.
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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
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			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
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	Account Description	Plant Investment: Additions	Retirements	Survivors	Salvage Rate: Realized	Future	Net Salvage: Realized	Future	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										
Black Mountain										
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%
Enviromental										
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%
Non-Enviromental										
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%
Valencia										
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%
Enviromental										
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 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
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 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												
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

Account Description		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

		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
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

	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
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

		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
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	Current Net Salvage	Current Total	Proposed (at 12/31/2014) Investment	Proposed Net Salvage	Proposed 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 Investment	Current 2015 Annualized Accrual			Proposed 2015 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
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		Net Salvage Reserve		Total Reserve	
		Amount	Ratio	Amount	Ratio	Amount	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			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
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

	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
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

	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
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	December 31, 2013 Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
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

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
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

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

		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
1999-2003	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

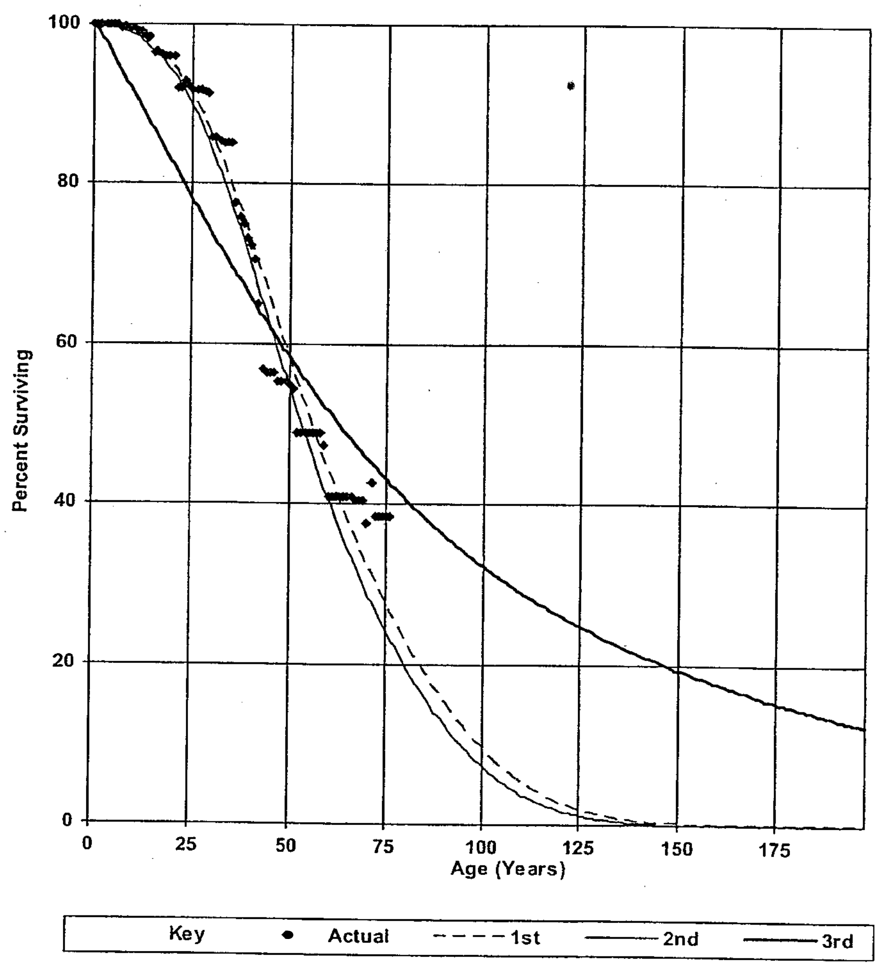
Placement Band: 1937-2013 Observation Band: 1999-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 58.8-L1.5 2nd: 56.2-L1.5 3rd: 89.0-O3



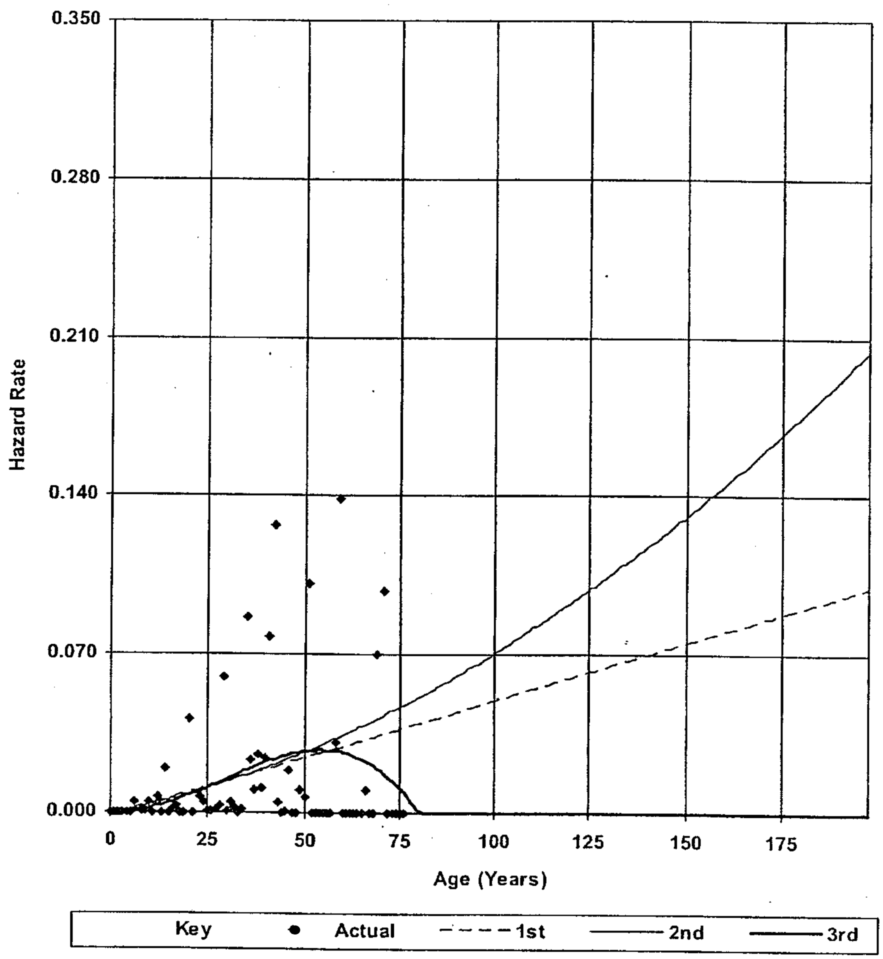
Schedule E

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

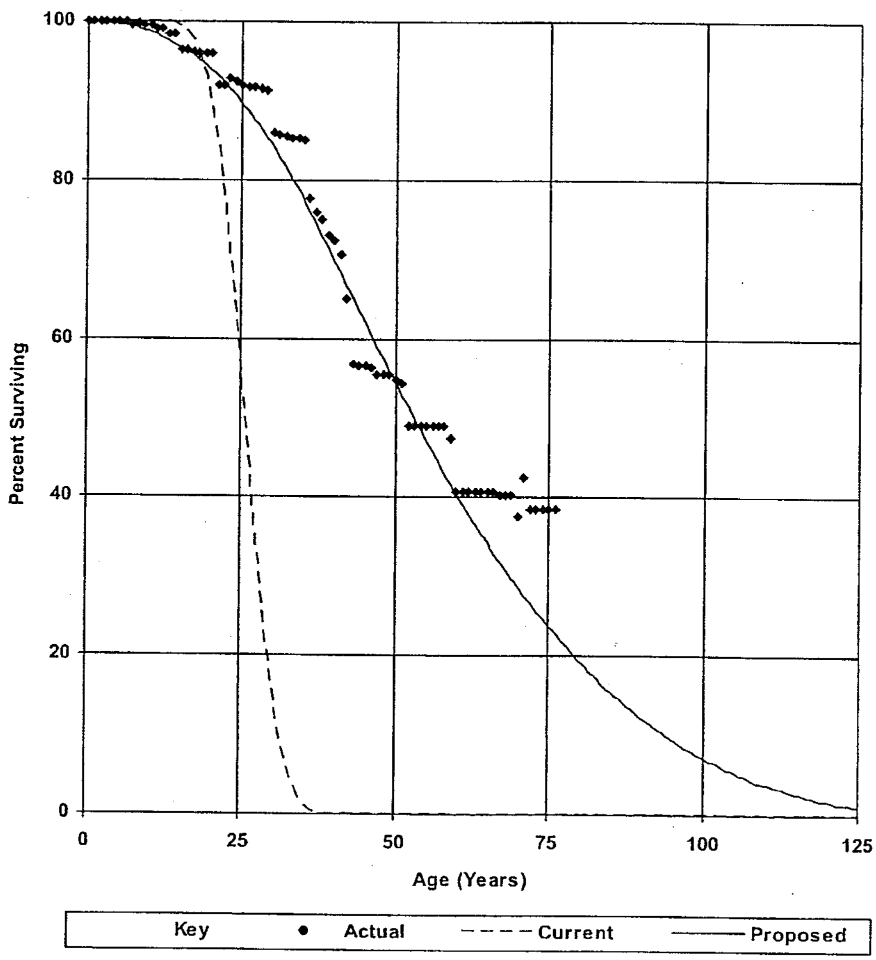


Schedule E
Page 1 of 1

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	

Direct Testimony of
Jason J. Rademacher

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

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. <u>Accumulated Deferred Income Tax ("ADIT").</u>

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. <u>Property Tax Expense.</u>

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.

Direct Testimony of
David J. Lewis

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

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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. <u>Working Capital.</u>

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.