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Transcript Exhibit(s)

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Part 7 of 8

For Part 8, see barcode 0000169263

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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

EXHIBIT
UNSE-20
ADMITTED

Rebuttal Testimony of

Denise A. Smith

on Behalf of

UNS Electric, Inc.

January 19, 2016

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DAS-R-1 Clean version of additional modifications of Rules and Regulations

DAS-R-2 Redlined version of addition modifications of Rules and Regulations

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Denise A. Smith. My business address is 88 E. Broadway Blvd., Tucson, Arizona 85702.

Q. Did you submit Direct Testimony on behalf of UNS Electric, Inc. ("UNS Electric" or "Company") in this Docket?

A. Yes.

Q. Have you reviewed the Direct Testimonies filed by the Utilities Division ("Staff") of the Arizona Corporation Commission ("Commission"), the Arizona Community Action Association ("ACAA") and Southwest Energy Efficiency Project ("SWEEP")?

A. Yes, I have.

Q. What subject matter do you cover in your Rebuttal Testimony?

A. I address: (i.) the positions of Staff and the ACAA regarding the proposed changes to the Rules and Regulations ("Rules"); (ii.) the concerns raised by the ACAA regarding deposits, CARES and Warms Spirits; (iii.) the concerns raised by SWEEP regarding Energy Efficiency ("EE"); and (iv.) the need for additional proposed modifications to the Rules.

II. RESPONSE TO STAFF.

Q. Do you agree with Staff's recommendations regarding the Rules?

A. The Company agrees to the following Staff recommendations without modification:

- At the end of Subsection 10.H. add "For Customers who choose to not have an automated meter installed or wish to replace an automated meter with a non-transmitting meter, the Special Meter Reading Fee will be a monthly recurring charge. The Automated Meter Opt-Out Set-Up Fee will only apply to those Customers who request the removal of an automated meter." The charge will also be reflected in the Statement of Charges.
- At the end of Subsection 11.I.6. add "listed in the Statement of Charges."

The Company agrees to the following Staff recommendations with minor modifications:

- Staff recommends adding "by the Company" to the end of Subsection 11.L.2. The Company recommends modifying this statement to "by the Company or its Agent" because the Company employs an outside credit and collections agency.
- Staff recommends adding language to the end of Subsection 4.A.6. that states, "This charge will only apply to customers who request this information more than once in a 12-month period". The Company recommends modifying this statement to "This charge will apply for each interval history request made or when Customers request their consumption history more than once in a 12-month period." This change is needed to clarify each additional request after the first annual request is assessed an administrative fee. The fee would not apply to future customer data available through the web or mobile devices.

The Company does not agree to the following Staff recommendation:

- Staff recommends that UNS Electric's proposed Subsection 12.H. not be approved for inclusion in its Rules. Subsection 12.H. provides that for customers who provide documentation certifying that they depend on electricity to power a life-sustaining medical device or if their medical condition warrants continuous electrical service and they accumulate a three (3) month bill, the customer will have the load limited to their premise in lieu of a disconnection of service. Load limiting would not necessarily be used only for customers with medical device alerts. It is a technology which could also be used at times of the year when extreme weather conditions might preclude service from being completely shut off. With respect to customers having a medical device or condition requiring continuous electricity, they are not exempt from disconnection for non-payment. Furthermore, no customer is guaranteed continuous electric service (e.g. storm-caused outage). For that reason, in the pamphlet provided to a customer to have a medical device alert placed on their account includes a signed statement by the physician indicating they have discussed contingency plans with their patient/our customer should the power go out. Another sentence in the pamphlet clearly states a medical device alert is not a discount program or a guarantee of uninterrupted service. In lieu of disconnecting service, limiting the amount of electricity into a home to provide ample power to operate a medical device and basic appliances - such as refrigeration, water supply, lighting, and small motors in the heating and cooling systems - should cause customers relief knowing regardless of the financial status of the utility account, service will not be interrupted by the utility.

Q. Are there any other issues that you would like to address from Staff's testimony?

A. Yes. The Direct Rate Design Testimony of Eric Van Epps recommends that the Company provide a draft Plan of Administration ("POA") for the DSM adjuster in the Company's rebuttal testimony. Following discussions to clarify Staff's request for a POA and what additional data is to be included, the Company will draft a POA that is consistent with A.A.C. R14-2-2401 *et seq.*, Electric Energy Efficiency Standards. Due to the nature of the request and timing associated with the development of the POA, the Company will provide a draft POA prior to the hearing in this matter.

III. RESPONSE TO ACAA.

Q. Do you agree with the ACAA's recommendations regarding holding harmless CARES customers from the modifications in UNS Electric's Rules regarding deposits?

A. No, and the Company further wishes to clarify that UNS Electric is not proposing to assess "additional" deposit amounts. Establishment or re-establishment of deposits occurs when customers demonstrate a repeated failure to pay their bill, or evidence is produced suggesting the probability a customer will not pay. If/when certain factors make it challenging for a customer to pay a bill and/or deposit, it is brought to UNS Electric's attention and every attempt will be made to provide a workable solution. These solutions may include referrals to assistance agencies, payment arrangements, or simply granting of extra time. UNS Electric has a long-standing history of working directly with individual customers to successfully meet their payment obligations. In 2015, UNS Electric granted 14,066 payment extensions to customers based on stated need.

Q. Do you agree with the ACAA's recommendations regarding not requiring a deposit when a customer files bankruptcy?

A. No, the United States Bankruptcy Code (Title 11, Chapter 3, Section 366) requires utilities to assess a deposit on post-petition accounts in order to furnish necessary assurance of payment. Furthermore, the language added to Subsection 3.B.3. of the Rules is consistent with ACC-approved Arizona Public Service Company ("APS") Schedule 2.7.6.1. Moreover, the assessment of deposits reduces instances of bad debt which all customers then must pay, regardless of bankruptcy.

Q. Do you agree with the ACAA's recommendations to add bill assistance and other related information to the disconnect notice?

A. Yes, the Company supports Ms. Zwick's request to add information to our Disconnect Notices notifying customers of agencies providing bill assistance opportunities in their area and information about weatherization agencies and information about the CARES discount. These changes will be incorporated as part of an upcoming bill redesign project.

Q. Does the Company support reallocating 10% of the Warm Spirits funding to agencies for program delivery?

A. The Company would be willing to allocate 10% of its matching funds for program delivery. All funding from customer donations, however, must be passed along to customers in need according to the information customers receive regarding their contributions to the Warm Spirits program ("100% of your contribution is passed along to customers in need").

Q. Ms. Zwick is concerned with the CARES program outreach. Please explain UNS Electric's current outreach methods to increase participation in the CARES program?

A. UNS Electric Customer Service Representatives distribute information on local assistance agencies when customers express an inability to pay their bill. The Company runs CARES informational campaigns for UNS Electric throughout the service areas that include bill inserts, advertising in newspapers and radio, social media posts and stories in the Company's quarterly e-newsletter "PluggedIn". In 2015, the Company implemented additional outreach efforts in Nogales, the most financially burdened area in UNS Electric's service territory. The outreach included transit shelter ads, posters and flyers distributed at community centers and community events.

IV. RESPONSE TO SWEEP.

Q. Should the addition of new Demand Side Management (DSM) programs be considered in the current UNS Electric rate case as requested by SWEEP?

A. No, it is not necessary or appropriate to consider additional DSM programs in this rate proceeding. A new UNS Electric EE Implementation Plan was approved by the Commission in Docket No. E-04204A-14-0178, Decision No. 75297 (October 27, 2015). The Company recognizes that rate design changes considered in this proceeding may require the development of new DSM programs. Following established protocol, the Company will file such programs under a new EE Implementation Plan or on a stand-alone basis through a DSM docket.

Q. Are additional DSM programs necessary in order to enable UNS Electric to meet the Energy Efficiency Standard and Rule ("EEES")?

A. No, not at this time. This issue was also evaluated recently in Docket No. E-04204A-14-0178. UNS Electric, through the 2015/2016 EE Implementation Plan, applied for funding for those new programs and measures it deemed cost-effective, prudent and implementation ready. UNS Electric currently projects cumulative 2015 savings are within a percentage point of the 2015 cumulative EEES mark of 9.5% of the prior year's retail sales. Current progress toward the standard was made despite numerous regulatory challenges at the beginning of the EEES.

Q. Do you agree with SWEEP's proposal to recover funding of DSM programs through base rates?

A. No, the funding of DSM programs should continue to be recovered through the DSM surcharge and not through increasing the base rates. Recovering DSM related expenses through the DSM surcharge provides ratepayers with important transparency of the investment being made in energy efficiency programming. As the regulatory environment for EE continues to evolve with the Clean Power Plan the recovery of expenses should be made through a resource-based decision model and transparent.

Q. Does UNS Electric plan to provide customer education or programming for customers on three part rates?

A. Yes, UNS Electric will support customers on three-part rates with a combination of education, technology, and EE programs. Education and outreach activities would include printed/on-line materials and direct customer engagement. An outline of a customer communication plan is included in the rebuttal testimony of Dallas Dukes.

An example of a technology solution, would be demand control equipment to reduce peak demand and improve energy efficiency. The demand would be controlled at a level

that the customer chooses. The equipment would stabilize electric use by managing equipment with thermal storage such as water heaters, air conditioners, hot tubs, etc. Electric loads like these can be turned off for small periods of time without effecting overall comfort or convenience.

The implementation of three-part rates provides more accurate price signals and gives the utility and customers expanded opportunities to implement EE measures. The vast majority if not all EE programs reduce demand. Demand reduction on the utility system has significant benefits to customers through reduced system costs

New demand-related DSM programs will be filed as part of a new EE Implementation Plan or on a stand-alone basis.

V. ADDITIONAL MINOR MODIFICATIONS TO RULES AND REGULATIONS.

Q. Why is the Company proposing additional minor modifications to the Rules?

A. Tucson Electric Power Company ("TEP") filed a rate case after UNS Electric filed this rate case. TEP proposed a few additional minor modifications to its Rules that were not included in the UNS Electric rate case. The Company would like to make a few minor modifications to the UNS Electric Rules to be consistent with TEP's Rules.

Q. What additional minor modifications to the Rules is the Company proposing?

A. There are four (4) minor modifications to the Rules the Company would like to make: (i.) Minor changes to Subsection 3.B.1.a. This is a non-substantive change; (ii.) Minor changes to Subsection 3.B.3. This is a non-substantive change; (iii.) Subsection 3.H. was deleted because it is not a current practice of the Company, and (iv.) Modifications to

Subsection 8.F.3. regarding the Company's liability. The current liability limitation language in Subsection 8.F.3. is focused on limitations on the Company's liability to customers for damages arising from the Company's provision of electric service. The language does not clearly address liability limitations related to third parties. The Arizona Court of Appeals recently addressed the appropriate scope of utility liability limitations and upheld limitations on utility liability to non-customers. Such a limitation acts to protect utility customers against undue expenses that may result in higher rates. Therefore, we are clarifying our liability limitation language in Section 8.F.3 to meet the ruling of the Court of Appeals and further protect our customers from potential liability to third-parties. The clean version of the additional modifications to the Rules is attached as **Exhibit DAS-R-1**. The redlined changes are attached as **Exhibit DAS-R-2**.

Q. Are there any other modifications to be made to the Rules?

A. Yes, there was an error made in Subsection 3.B.3. of the proposed UNS Electric redlined Rules. Due to an oversight, the language, "or more" was not deleted and should have been redlined in this Subsection. This is the same rule that was proposed in 3.B.1.a.

Q. Does this conclude your Rebuttal Testimony?

A. Yes.

Exhibit DAS-R-1

SECTION 3
ESTABLISHMENT OF SERVICE

A. Information from New Applicants

1. The Company may obtain the following minimum information from each application for service:

   a. Name or names of Applicant(s);

   b. Service address or location and telephone number;

   c. Billing address/telephone number, if different than service address;

   d. Social Security Number or Driver's License number and date of birth to be consistent with verifiable information on legal identification;

   e. Address where service was provided previously;

   f. Date Applicant will be ready for service;

   g. Statement of whether premises have been supplied with electric service previously;

   h. Purpose for which service is to be used;

   i. Statement of whether Applicant is owner or tenant of or agent for the premises;

   j. Information concerning the energy and demand requirements of the Customer; and

   k. Type and kind of life-support equipment, if any, used by the Customer or at the service address.

2. Where service is requested by two (2) or more individuals, the Company will have the right to collect the full amount owed to the Company from any one of the Applicants.

3. The supplying of electric service by the Company and the Customer's acceptance of that electric service will be deemed to constitute an agreement by and between the Company and the Customer for delivery, acceptance of and payment for electric service under the Company's applicable Rates, and Rules and Regulations.

4. The term of any agreement not otherwise specified will become operative on the day the Customer's installation is connected to the Company's facilities for the purpose of taking electric energy.

5. The Company may require a written contract with special guarantees from Applicants whose unusual characteristics of load or location would require excessive investment in facilities or whose requirements for service are of a special nature.

6. Signed contracts may be required for service to commercial and industrial establishments. No contract or any modification of the contract will be binding upon the Company until executed by a duly authorized representative of the Company.

7. Where an occupant of the premises who owes a debt to the Company, but is not the Applicant or the Customer, the occupant shall also be jointly and severally liable for the bills rendered to the premises.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

B. Deposits

1. The Company may require from any present or prospective Customer a deposit to guarantee payment of all bills. This deposit may be retained by the Company until service is discontinued and all bills have been paid; except as provided in Subsection B.3. below. Upon proper application by the Customer, the Company will then return said deposit, together with any unpaid interest accrued thereon from the date of commencement of service or the date of making the deposit, whichever is later. The Company will be entitled to apply said deposit together with any unpaid interest accrued thereon, to any indebtedness for the same class of service owed to the Company for electric service furnished to the Customer making the deposit. When said deposit has been applied to any such indebtedness, the Customer's electric service may be discontinued until all such indebtedness of the Customer is paid and a like deposit is again made with the Company by the Customer. No interest will accrue on any deposit after discontinuance of the service to which the deposit relates.

   The Company will not require a deposit from a new Applicant for residential service if the Applicant is able to meet any of the following requirements:

   a. The Applicant has had service with the Company within the past two (2) years and was not delinquent in payment twice during the last twelve (12) consecutive months of service and was never disconnected for nonpayment; or

   b. The Applicant can produce a letter of credit or verification from an electric utility where service of a comparable nature was last received by Applicant, which states Applicant had a timely payment history at time of service discontinuation; or

   c. Instead of a deposit, the Company receives deposit guarantee notification from a social or governmental agency acceptable to the Company. A surety bond may be provided as security for the Company in an amount equal to the required deposit.

2. Cash deposits held by the Company twelve (12) months or longer will earn interest at the established one-year Treasury Constant Maturities rate, effective on the first business day of each year, as published in the Federal Reserve website.

3. Residential Customers – The Company may require a residential Customer to establish or reestablish a deposit if the Customer becomes delinquent in the payment of two (2) bills or has been disconnected from service during the last twelve (12) months.

   Deposits or other instruments of credit will automatically expire or be refunded or credited to the Customer's account after twelve (12) consecutive months of service following full payment of deposit during which time the Customer has not been delinquent two (2) times or has not been disconnected for non-payment, unless the Customer has filed bankruptcy in the last twelve (12) months.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

4. Non-Residential Customers – The Company may require a non-residential Customer to establish or reestablish a deposit if the Customer becomes delinquent in the payment of two (2) bills or if the Customer has been disconnected for non-payment during the last twelve (12) months, or when the Customer's financial condition may jeopardize the payment of their bill.

   Deposits and non-cash deposits on file with the Company will be reviewed after twenty-four (24) consecutive months of service and will be returned provided the Customer has not been delinquent two (2) times or disconnected for non-payment in the most recent twelve (12) month period, unless the Customer's financial condition warrants extension of the deposit.

5. The Company may review the Customer's usage after service has been connected and adjust the deposit amount based upon the Customer's actual usage.

6. A separate deposit may be required for each meter installed.

7. Residential Customer deposits will not exceed two (2) times that Customer's estimated average monthly bill. Non-residential Customer deposits will not exceed two and one-half (2.5) times that Customer's maximum estimated monthly bill. If actual usage history is available, then that usage, adjusted for normal weather, will be the basis for the estimate.

8. The posting of a deposit will not preclude the Company from terminating service when the termination is due to the Customer's failure to perform any obligation under the agreement for service or any of these Rules and Regulations.

C. Conditions for Supplying Service

The Company reserves the right to determine the conditions under which service will be provided. Conditions for service and extending service to the Customer will be based upon the following:

1. Customer has wired his premises in accordance with the National Electric Code, City, County and/or State codes, whichever are applicable.

2. If the Company determines that there is a reasonable basis to believe that the Customer's premises poses a safety risk to Company employees, then the Company may, at its option, install a meter or facilities with remote connect and/or disconnect capabilities.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

3. Customer has installed the meter loop in a suitable location approved by the Company.

4. In the case of a mobile home, the meter loop must be attached to a meter pole or to an approved support.

5. In case of temporary construction service, the meter loop must be attached to an approved support.

6. All meter loop installations must be in accordance with the Company's specifications and located at an outdoor location accessible to the Company.

7. Individual Customers may be required to have their property corner pins and/or markers installed to establish proper right-of-way locations.

8. Developers must have all property corner pins and/or markers installed necessary to establish proper locations to supply electric service to individual lots within subdivisions.

9. Where the installation requires more than one meter for service to the premises, each meter panel must be permanently marked (not painted) by the contractor or Customer to properly identify the portion of the premises being served.

10. The identification will be the same as the apartment, office, etc., served by that meter socket. The identifying marking placed on each meter panel will be impressed into or raised from a tab of aluminum, brass or other approved non-ferrous metal with minimum one-fourth (1/4) inch-high letters. This tag must be riveted to the meter panel. The impression must be deep enough to prevent the identification(s) from being obscured by subsequent painting of the building and attached service equipment.

11. The Company may require the assistance of the Customer and/or the Customer's contractor to open the apartments or offices at the time the meters are set, in order to verify that each meter socket actually serves the apartment or office indicated by the marking tag. In the case of multiple buildings the building or unit number and street address will be identified on the pull section in the manner described above.

D. Grounds for Refusal of Service

The Company may refuse to establish service if any of the following conditions exist:

1. When the Applicant or affiliate of the Applicant with common ownership has an outstanding amount due for the same class of electric service with the Company and the Applicant is unwilling to make arrangements with the Company for payment, in such cases, the Company shall be entitled to transfer the balance due or credit owed on the terminated service to any other active account of the Customer for the same class of service. The failure of the Customer to pay the active account shall result in the suspension or termination of service.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

2. A condition exists which, in the Company's judgment, is unsafe or hazardous to the Applicant, the general population, or the Company's personnel or facilities;

3. The Applicant refuses to provide the Company with a deposit when the Customer has failed to meet the credit criteria for waiver of deposit requirements;

4. Customer is known to be in violation of the Company's Rates or Rules and Regulations;

5. Customer fails to furnish the funds, service, equipment, and/or rights-of-way necessary to serve the Customer and which have been specified by the Company as a condition for providing service;

6. Customer fails to provide safe access to the meter that would be serving the Customer;

7. Applicant falsifies his or her identity for the purpose of obtaining service;

8. Service is requested by an Applicant and a prior Customer, who is either living with the Applicant, or who is an occupant of the premises who owes a debt to the Company from the same class of service from the same or a prior service address;

9. The Applicant is acting as an agent for a prior Customer who is deriving benefits from the energy supplied and who owes a delinquent bill from the same class of service from the same or a prior service address;

10. There is evidence of tampering or energy diversion.

11. Where the Company has a reasonable belief that the Applicant has common ownership with an affiliate that owes a delinquent bill for the same class of service.

E. Service Establishment, Reestablishment or Reconnection Charge

1. The Company will make a charge, as approved by the ACC, for service transfer for meter reads only set forth as Fee No. 1 in the UNS Electric Statement of Charges.

2. The Company may make a charge, as approved by the ACC, for the establishment, reestablishment, or reconnection of service. The charge for establishment, reestablishment or reconnection of service during regular business hours is set forth as Fee No. 4 in the UNS Electric Statement of Charges.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

3. Should service be established, reestablished or reconnected during a period other than the Company's regular business hours, at the Customer's request, the Customer may be required to pay an after-hour charge for the service connection set forth as Fee No. 5 in the UNS Electric Statement of Charges. Where the Company's scheduling will not permit service establishment, reestablishment or reconnection of service on the same day as requested, the Customer can elect to pay the after-hour charge for establishment that day, or service will be established on the next available business day. Even so, a Customer's request to have the Company establish service after-hours is subject to the Company having Staff available; there is no guarantee that the Company will have the staffing available for service establishment, reestablishment or reconnection of service outside of regular business hours.

4. For the purpose of this Rule, the definition of service establishment is where the Customer's facilities are ready and acceptable to the Company, the Applicant has obtained all required permits and/or inspections indicating that the Applicant's facilities comply with local construction safety and governmental standards and regulations, and the Company needs only to install a meter, read a meter, or turn the service on.

5. Service Reconnection Charge

   Whenever the Company has discontinued service under its usual operating procedures because of any default by the Customer as provided herein, a reconnection charge, not to exceed the charge for the reestablishment of service as set forth as Fee Nos. 4-5 in the UNS Electric Statement of Charges, shall be made and may be collected by the Company before service is restored. When, due to the behavior of the Customer, it has been necessary to discontinue service utilizing other than usual operating procedures, the Company shall be entitled to charge Fee No. 6 to restore service, as set forth in the UNS Electric Statement of Charges.

F. Temporary Service

1. Applicants for temporary service may be required to pay Line Extension charges in accordance with Section 7.C.9.d.

2. Where the duration of service is to be less than one (1) month, the Applicant will also be required to advance a sum of money equal to the estimated bill for service.

3. Where the duration of service is to exceed one (1) month, the Applicant may also be required to meet the deposit requirements of the Company, as outlined in Subsection B.1. above.

4. If at any time during the term of the agreement for service the character of a temporary Customer's operations changes so that, in the opinion of the Company, the Customer is classified as permanent, the terms of the Company's Line Extension rules will apply.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

G. Identification of Load and Premises

Upon request of the Company, the electric load and premises to be served by the Company must be clearly identified by the Customer at the time of application. If the service address is not recognized in terms of commonly used identification system, the Customer may be required to provide specific written directions and/or legal descriptions before the Company will be required to act upon a request for electric service.

H. Tampering With or Damaging Company Equipment

1. The Customer agrees, when accepting service, that no one except authorized Company employees or agents of the Company will be allowed to remove or replace any Company owned equipment installed on Customer's property.

2. No person, except an employee or agent acting on behalf of the Company shall alter, remove or make any connection to the Company's meter or service equipment.

3. No meter seal may be broken or removed by anyone other than an employee or agent acting on behalf of the Company; however, the Company may give its prior consent to break the seal by an approved electrician employed by a Customer when deemed necessary by the Company.

4. The Customer will be held responsible for any broken seals, tampering, or interfering with the Company's meter(s) or any other Company owned equipment installed on the Customer's premises. In cases of tampering with meter installations, interfering with the proper working thereof, or any tampering, interfering, theft, or service diversion, including the falsification of Customer read-meter readings, Customer will be subject to immediate discontinuance of service. The Company will be entitled to collect from the Customer or other person benefitting from the service, under the appropriate Rate, for all power and energy not recorded on the meter as the result of such tampering, or other theft of service, and also additional security deposits as well as all expenses incurred by the Company for property damages, investigation of the illegal act, and all legal expenses and court costs incurred by the Company.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

5. The Customer will be held liable for any loss or damage occasioned or caused by the Customer's negligence, want of proper care or wrongful act or omission on the part of any Customer's agents, employees, licensees or contractors.

I. Access

1. The Customer is responsible for providing safe access to Company facilities. The Company's authorized agents shall have satisfactory unassisted twenty-four (24) hour a day, seven (7) days a week access to the Company's equipment located on Customer's premise for the purpose of service connection, service disconnection, operation, maintenance, repair and service restoration work that the Company may need to perform.

2. If additional resources are required to gain safe access to perform service establishment, disconnection, meter reading, or routine maintenance, due to an affirmative, wrongful, and/or criminal act by the Customer, the Company will be entitled to collect from the Customer all expenses incurred by the Company for additional resources including: investigation of access, all legal expenses, and court costs.

J. Customer-Specific Information

Customer-specific information shall not be released without specific prior Customer authorization unless the information is requested by law enforcement or other public agency, or is requested by the Commission or its staff, or is reasonably required for legitimate account collection activities, or is necessary to provide safe and reliable service to the Customer. Such Customer authorization may be obtained electronically, in writing, or orally, as long as the oral authorization is recorded.

SECTION 8
PROVISION OF SERVICE

A. Company Responsibility

1. The Company will be responsible for the safe transmission and distribution of electricity until it passes the point of delivery to the Customer.

2. The Company will be responsible for maintaining in safe operating condition all meters, equipment and fixtures installed on the Customer's premises by the Company for the purpose of delivering electric service to the Customer. However, the Company will not be responsible for the condition of meters, equipment, and fixtures damaged or altered by the Customer.

3. The Company may, at its option, refuse service until the Customer has obtained all required permits and/or inspections indicating that the Customer's facilities comply with local construction and safety standards, including any applicable Company specifications.

4. The Company will determine, in its sole discretion, the type of service (including voltage and Point of Delivery) to be furnished for utilization by the Customer. This includes determinations involving: 1) requirements to take Primary Service and Metering; and 2) service voltage (including for any new on-site generation installations or generation retrofits at the Customer's premises).

B. Customer Responsibility

1. Each Customer will be responsible for maintaining in safe operating condition all Customer facilities on the Customer's side of the point of delivery.

2. Each Customer will be responsible for safeguarding all Company property installed in or on the Customer's premises for the purpose of supplying electric service to that Customer.

3. Each Customer will exercise all reasonable care to prevent loss or damage to Company property, excluding ordinary wear and tear. The Customer will be responsible for loss of or damage to Company property on the Customer's premises arising from neglect, carelessness, misuse, diversion, or tampering and will reimburse the Company for the cost of necessary repairs or replacements.

4. Each Customer will be responsible for payment for any equipment damage and/or estimated unmetered usage and all reasonable costs resulting from unauthorized breaking of seals, interfering, tampering or bypassing the Company meter.

5. Each Customer will be responsible for notifying the Company of any equipment failure identified in the Company's equipment.

SECTION 8
PROVISION OF SERVICE
(continued)

6. Each Customer will be responsible for informing the Company of, and meeting the Company's requirements regarding on-site or distributed generation (including distributed renewable resources and combined heat and power facilities) that the Customer or the Customer's agent intends to interconnect to the Company's transmission or distribution system. This includes compliance with all requirements contained within the Company's most current Interconnection Requirements for Distributed Generation, and the terms and conditions of the Company's Agreement for the Interconnection of Customer's Facility. Customer must also agree to enter into the Interconnection Agreement with the Company. Further, any interconnection must be in accordance with any applicable Commission regulation and order governing interconnection, as well as applicable laws.

7. The Customer, at his expense, may install, maintain and operate check-measuring equipment as desired and of a type approved by the Company, provided that this equipment will be installed so as not to interfere with operation of the Company's equipment. This is also provided that no electric energy will be remetered or submetered for resale to another or to others, except where such remetering will be done in accordance with the applicable orders of the Commission.

C. Continuity of Service

The Company will make reasonable efforts to supply a satisfactory and continuous level of service. However, the Company will not be responsible for any damage or claim of damage attributable to any interruption or discontinuation of service resulting from:

1. Any cause against which the Company could not have reasonably foreseen, or made provision for (*i.e* force majeure, see Subsection 8.E.);

2. Intentional service interruptions to make repairs or perform routine maintenance; or

3. Curtailment, including brownouts or blackouts.

D. Service Interruptions

1. The Company will make reasonable efforts to reestablish service within the shortest possible time when service interruptions occur.

2. In the event of a national emergency or local disaster resulting in disruption of normal service, the Company may, in the public interest, interrupt service to other Customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

SECTION 8
PROVISION OF SERVICE
(continued)

3. When the Company plans to interrupt service for more than four (4) hours to perform necessary repairs or maintenance, the Company will attempt to inform affected Customers at least twenty-four (24) hours in advance of the scheduled date and these repairs will be completed in the shortest possible time to minimize the inconvenience to the Customers of the Company.

4. The Commission will be notified of interruption in service affecting the entire system or any significant portion thereof. The interruption of service and cause will be reported by telephone to the Commission within four (4) hours after the responsible Company representative becomes aware of said interruption. A written report to the Commission will follow.

E. Interruption of Service and Force Majeure

1. The Company will make reasonable provision to supply a satisfactory and continuous electric service, but does not guarantee a constant or uninterrupted supply of electricity. The Company will not be liable for any damage or claim of damage attributable to any temporary, partial or complete interruption or discontinuance of electric service attributable to a force majeure condition as set forth in Subsections 8.E.4. and 8.E.5. or to any other cause which the Company could not have reasonably foreseen and made provision against, or which, in the Company's judgment, is necessary to permit repairs or changes to be made in the Company's electric generating, transmission, or distribution equipment, or to eliminate the possibility of damage to the Company's property or to the person or property of others.

2. Whenever the Company deems a condition exists that warrants interruption or limitation in the service being rendered, this limitation or interruption will not constitute a breach of contract and will not render the Company liable for damages suffered thereby or excuse the Customer from further fulfillment of the contract.

3. The use of electric energy upon the Customer's premises is at the risk of the Customer. The Company's liability will cease at the point where its facilities are connected to the Customer's wiring.

4. Neither the Company nor the Customer will be liable to the other for any act, omission, or circumstances (including, but not limited to, the Company's inability to provide electric service) occasioned by or in consequence of the following:

   a. flood, rain, wind, storm, lightning, earthquake, fire, landslide, washout or other acts of the elements;

   b. accident or explosion;

   c. war, rebellion, civil disturbance, mobs, riot, blockade or other act of the public enemy;

   d. acts of God;

   e. interference of civil and/or military authorities;

SECTION 8
PROVISION OF SERVICE
(continued)

f. strikes, lockouts, or other labor difficulties;

g. vandalism, sabotage, or malicious mischief;

h. usurpation of power, or the laws, rules, regulations, or orders made or adopted by any regulatory or other governmental agency or body (federal, state or local) having jurisdiction of any of the business or affairs of the Company or the Customer, direct or indirect;

i. breakage or accidents to equipment or facilities;

j. lack, limitation or loss of electrical or fuel supply; or

k. any other casualty or cause beyond the reasonable control of the Company or the Customer, whether or not specifically provided herein and without limitation to the types enumerated, and which by exercise of due diligence the Company or the Customer is unable to overcome.

5. A failure to settle or prevent any strike or other controversy with employees or with anyone purporting or seeking to represent employees will not be considered to be a matter within the control of the Company.

6. Nothing contained in this Section will excuse the Customer from the obligation of paying for electricity delivered or services rendered.

F. General Liability

1. Company will not be responsible for any third-party claims against Company that arise from Customer's use of Company's electric services, unless such claims are caused by the Company's willful misconduct or gross negligence.

2. Customer will indemnify, defend and hold harmless the Company (including the costs of reasonable attorney's fees) against all claims (including, without limitation, claims for damages to any business or property, or injury to, or death of, any person) arising out of any wrongful or negligent acts or omissions of the Customer, or the Customer's agents, in connection with the Company's service or facilities.

3. Except in the case of the Company's willful misconduct or gross negligence, the Company will not be liable to Customer or any other party for damages of any nature arising from errors, mistakes, omissions, interruptions, or delays of the Company, its agents, servants, or employees, in the course of, or related to, establishing, furnishing, rearranging, moving, terminating, or changing the service or facilities or equipment, except that for an interruption of service to a Customer, to the extent resulting from error, mistake, omission, interruption or delay by the Company, the Company's liability, if any, to the Customer shall not exceed an amount equal to the charges for service applicable under the Company's Rates (calculated on a proportionate basis where appropriate) for the period of service interruption.

SECTION 8
PROVISION OF SERVICE
(continued)

4. In no event will the Company be liable for any incidental, indirect, special, or consequential damages (including lost revenue or profits) of any kind whatsoever regardless of the cause or foreseeability thereof.

5. The Company will not be responsible in an occasion for any loss or damage caused by the negligence or wrongful act of the Customer or any of his agents, employees or licensees in installing, maintaining, using, operating or interfering with any electric facilities.

G. Construction Standards and Safety

The Company will construct all facilities in accordance with the provisions of the ANSI C2 Standards (National Electric Safety Code, 2007 edition, and other amended editions as are adopted by the ACC), the 2007 ANSI B31.1 Standards, the ASME Boiler and Pressure Vessel Code, and other applicable American National Standards Institute Codes and Standards, except for those changes the ACC makes or permits from time to time. In the case of conflict between codes and standards, the more rigid code or standard will apply.

Exhibit DAS-R-2

SECTION 3
ESTABLISHMENT OF SERVICE

A. Information from New Applicants

1. The Company may obtain the following minimum information from each application for service:

   a. Name or names of Applicant(s);

   b. Service address or location and telephone number;

   c. Billing address/telephone number, if different than service address;

   d. Social Security Number or Driver's License number and date of birth to be consistent with verifiable information on legal identification;

   e. Address where service was provided previously;

   f. Date Applicant will be ready for service;

   g. Statement of whether premises have been supplied with electric service previously;

   h. Purpose for which service is to be used;

   i. Statement of whether Applicant is owner or tenant of or agent for the premises;

   j. Information concerning the energy and demand requirements of the Customer; and

   k. Type and kind of life-support equipment, if any, used by the Customer or at the service address.

2. Where service is requested by two (2) or more individuals, the Company will have the right to collect the full amount owed to the Company from any one of the Applicants.

3. The supplying of electric service by the Company and the Customer's acceptance of that electric service will be deemed to constitute an agreement by and between the Company and the Customer for delivery, acceptance of and payment for electric service under the Company's applicable Rates, and Rules and Regulations.

4. The term of any agreement not otherwise specified will become operative on the day the Customer's installation is connected to the Company's facilities for the purpose of taking electric energy.

5. The Company may require a written contract with special guarantees from Applicants whose unusual characteristics of load or location would require excessive investment in facilities or whose requirements for service are of a special nature.

6. Signed contracts may be required for service to commercial and industrial establishments. No contract or any modification of the contract will be binding upon the Company until executed by a duly authorized representative of the Company.

7. Where an occupant of the premises who owes a debt to the Company, but is not the Applicant or the Customer, the occupant shall also be jointly and severally liable for the bills rendered to the premises.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

B. Deposits

1. The Company may require from any present or prospective Customer a deposit to guarantee payment of all bills. This deposit may be retained by the Company until service is discontinued and all bills have been paid; except as provided in Subsection B.3. below. Upon proper application by the Customer, the Company will then return said deposit, together with any unpaid interest accrued thereon from the date of commencement of service or the date of making the deposit, whichever is later. The Company will be entitled to apply said deposit together with any unpaid interest accrued thereon, to any indebtedness for the same class of service owed to the Company for electric service furnished to the Customer making the deposit. When said deposit has been applied to any such indebtedness, the Customer's electric service may be discontinued until all such indebtedness of the Customer is paid and a like deposit is again made with the Company by the Customer. No interest will accrue on any deposit after discontinuance of the service to which the deposit relates.

   The Company will not require a deposit from a new Applicant for residential service if the Applicant is able to meet any of the following requirements:

   a. The Applicant has had service ~~of a comparable nature~~ with the Company within the past two (2) years and was not delinquent in payment twice during the last twelve (12) consecutive months of service and~~or~~ was never~~not~~ disconnected for nonpayment; or

   b. The Applicant can produce a letter of credit or verification from an electric utility where service of a comparable nature was last received by Applicant, which states Applicant had a timely payment history at time of service discontinuation; or

   c. Instead of a deposit, the Company receives deposit guarantee notification from a social or governmental agency acceptable to the Company. A surety bond may be provided as security for the Company in an amount equal to the required deposit.

2. Cash deposits held by the Company twelve (12) months or longer will earn interest at the established one-year Treasury Constant Maturities rate, effective on the first business day of each year, as published in the Federal Reserve website.

3. Residential Customers – The Company may require a residential Customer to establish or reestablish a deposit if the Customer becomes delinquent in the payment of two (2) ~~or more~~ bills or has been disconnected from service during the last twelve (12) months.

   Deposits or other instruments of credit will automatically expire or be refunded or credited to the Customer's account after twelve (12) consecutive months of service following full payment of deposit during which time the Customer has not been delinquent two (2) times or has not been disconnected for non-payment, unless the Customer has filed bankruptcy in the last twelve (12) months.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

4. Non-Residential Customers – The Company may require a non-residential Customer to establish or reestablish a deposit if the Customer becomes delinquent in the payment of two (2) bills or if the Customer has been disconnected for non-payment during the last twelve (12) months, or when the Customer's financial condition may jeopardize the payment of their bill.

   Deposits and non-cash deposits on file with the Company will be reviewed after twenty-four (24) consecutive months of service and will be returned provided the Customer has not been delinquent two (2) times or disconnected for non-payment in the most recent twelve (12) month period, unless the Customer's financial condition warrants extension of the deposit.

5. The Company may review the Customer's usage after service has been connected and adjust the deposit amount based upon the Customer's actual usage.

6. A separate deposit may be required for each meter installed.

7. Residential Customer deposits will not exceed two (2) times that Customer's estimated average monthly bill. Non-residential Customer deposits will not exceed two and one-half (2.5) times that Customer's maximum estimated monthly bill. If actual usage history is available, then that usage, adjusted for normal weather, will be the basis for the estimate.

8. The posting of a deposit will not preclude the Company from terminating service when the termination is due to the Customer's failure to perform any obligation under the agreement for service or any of these Rules and Regulations.

C. Conditions for Supplying Service

The Company reserves the right to determine the conditions under which service will be provided. Conditions for service and extending service to the Customer will be based upon the following:

1. Customer has wired his premises in accordance with the National Electric Code, City, County and/or State codes, whichever are applicable.

2. If the Company determines that there is a reasonable basis to believe that the Customer's premises poses a safety risk to Company employees, then the Company may, at its option, install a meter or facilities with remote connect and/or disconnect capabilities.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

3. Customer has installed the meter loop in a suitable location approved by the Company.

4. In the case of a mobile home, the meter loop must be attached to a meter pole or to an approved support.

5. In case of temporary construction service, the meter loop must be attached to an approved support.

6. All meter loop installations must be in accordance with the Company's specifications and located at an outdoor location accessible to the Company.

7. Individual Customers may be required to have their property corner pins and/or markers installed to establish proper right-of-way locations.

8. Developers must have all property corner pins and/or markers installed necessary to establish proper locations to supply electric service to individual lots within subdivisions.

9. Where the installation requires more than one meter for service to the premises, each meter panel must be permanently marked (not painted) by the contractor or Customer to properly identify the portion of the premises being served.

10. The identification will be the same as the apartment, office, etc., served by that meter socket. The identifying marking placed on each meter panel will be impressed into or raised from a tab of aluminum, brass or other approved non-ferrous metal with minimum one-fourth (1/4) inch-high letters. This tag must be riveted to the meter panel. The impression must be deep enough to prevent the identification(s) from being obscured by subsequent painting of the building and attached service equipment.

11. The Company may require the assistance of the Customer and/or the Customer's contractor to open the apartments or offices at the time the meters are set, in order to verify that each meter socket actually serves the apartment or office indicated by the marking tag. In the case of multiple buildings the building or unit number and street address will be identified on the pull section in the manner described above.

D. Grounds for Refusal of Service

The Company may refuse to establish service if any of the following conditions exist:

1. When the Applicant or affiliate of the Applicant with common ownership has an outstanding amount due for the same class of electric service with the Company and the Applicant is unwilling to make arrangements with the Company for payment, in such cases, the Company shall be entitled to transfer the balance due or credit owed on the terminated service to any other active account of the Customer for the same class of service. The failure of the Customer to pay the active account shall result in the suspension or termination of service.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

2. A condition exists which, in the Company's judgment, is unsafe or hazardous to the Applicant, the general population, or the Company's personnel or facilities;

3. The Applicant refuses to provide the Company with a deposit when the Customer has failed to meet the credit criteria for waiver of deposit requirements;

4. Customer is known to be in violation of the Company's Rates or Rules and Regulations;

5. Customer fails to furnish the funds, service, equipment, and/or rights-of-way necessary to serve the Customer and which have been specified by the Company as a condition for providing service;

6. Customer fails to provide safe access to the meter that would be serving the Customer;

7. Applicant falsifies his or her identity for the purpose of obtaining service;

8. Service is requested by an Applicant and a prior Customer, who is either living with the Applicant, or who is an occupant of the premises who owes a debt to the Company from the same class of service from the same or a prior service address;

9. The Applicant is acting as an agent for a prior Customer who is deriving benefits from the energy supplied and who owes a delinquent bill from the same class of service from the same or a prior service address;

10. There is evidence of tampering or energy diversion.

11. Where the Company has a reasonable belief that the Applicant has common ownership with an affiliate that owes a delinquent bill for the same class of service.

E. Service Establishment, Reestablishment or Reconnection Charge

1. The Company will make a charge, as approved by the ACC, for service transfer for meter reads only set forth as Fee No. 1 in the UNS Electric Statement of Charges.

2. The Company may make a charge, as approved by the ACC, for the establishment, reestablishment, or reconnection of service. The charge for establishment, reestablishment or reconnection of service during regular business hours is set forth as Fee No. 4 in the UNS Electric Statement of Charges.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

3. Should service be established, reestablished or reconnected during a period other than the Company's regular business hours, at the Customer's request, the Customer may be required to pay an after-hour charge for the service connection set forth as Fee No. 5 in the UNS Electric Statement of Charges. Where the Company's scheduling will not permit service establishment, reestablishment or reconnection of service on the same day as requested, the Customer can elect to pay the after-hour charge for establishment that day, or service will be established on the next available business day. Even so, a Customer's request to have the Company establish service after-hours is subject to the Company having Staff available; there is no guarantee that the Company will have the staffing available for service establishment, reestablishment or reconnection of service outside of regular business hours.

4. For the purpose of this Rule, the definition of service establishment is where the Customer's facilities are ready and acceptable to the Company, the Applicant has obtained all required permits and/or inspections indicating that the Applicant's facilities comply with local construction safety and governmental standards and regulations, and the Company needs only to install a meter, read a meter, or turn the service on.

5. Service Reconnection Charge

   Whenever the Company has discontinued service under its usual operating procedures because of any default by the Customer as provided herein, a reconnection charge, not to exceed the charge for the reestablishment of service as set forth as Fee Nos. 4-5 in the UNS Electric Statement of Charges, shall be made and may be collected by the Company before service is restored. When, due to the behavior of the Customer, it has been necessary to discontinue service utilizing other than usual operating procedures, the Company shall be entitled to charge Fee No. 6 to restore service, as set forth in the UNS Electric Statement of Charges.

F. Temporary Service

1. Applicants for temporary service may be required to pay Line Extension charges in accordance with Section 7.C.9.d.

2. Where the duration of service is to be less than one (1) month, the Applicant will also be required to advance a sum of money equal to the estimated bill for service.

3. Where the duration of service is to exceed one (1) month, the Applicant may also be required to meet the deposit requirements of the Company, as outlined in Subsection B.1. above.

4. If at any time during the term of the agreement for service the character of a temporary Customer's operations changes so that, in the opinion of the Company, the Customer is classified as permanent, the terms of the Company's Line Extension rules will apply.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

G. Identification of Load and Premises

Upon request of the Company, the electric load and premises to be served by the Company must be clearly identified by the Customer at the time of application. If the service address is not recognized in terms of commonly used identification system, the Customer may be required to provide specific written directions and/or legal descriptions before the Company will be required to act upon a request for electric service.

~~H. Identification of Responsible Party~~

~~Any person applying on behalf of another Customer for service to be connected in the name of or in care of another Customer must furnish to the Company written approval from that Customer guaranteeing payment of all bills under the account. The Customer is responsible in all cases for service supplied to the premises until the Company has received proper notice of the effective date of any change. The Customer shall also promptly notify the Company of any change in physical or electronic billing address.~~

H~~I~~. Tampering With or Damaging Company Equipment

1. The Customer agrees, when accepting service, that no one except authorized Company employees or agents of the Company will be allowed to remove or replace any Company owned equipment installed on Customer's property.

2. No person, except an employee or agent acting on behalf of the Company shall alter, remove or make any connection to the Company's meter or service equipment.

3. No meter seal may be broken or removed by anyone other than an employee or agent acting on behalf of the Company; however, the Company may give its prior consent to break the seal by an approved electrician employed by a Customer when deemed necessary by the Company.

4. The Customer will be held responsible for any broken seals, tampering, or interfering with the Company's meter(s) or any other Company owned equipment installed on the Customer's premises. In cases of tampering with meter installations, interfering with the proper working thereof, or any tampering, interfering, theft, or service diversion, including the falsification of Customer read-meter readings, Customer will be subject to immediate discontinuance of service. The Company will be entitled to collect from the Customer or other person benefitting from the service, under the appropriate Rate, for all power and energy not recorded on the meter as the result of such tampering, or other theft of service, and also additional security deposits as well as all expenses incurred by the Company for property damages, investigation of the illegal act, and all legal expenses and court costs incurred by the Company.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

5. The Customer will be held liable for any loss or damage occasioned or caused by the Customer's negligence, want of proper care or wrongful act or omission on the part of any Customer's agents, employees, licensees or contractors.

IJ. Access

1. The Customer is responsible for providing safe access to Company facilities. The Company's authorized agents shall have satisfactory unassisted twenty-four (24) hour a day, seven (7) days a week access to the Company's equipment located on Customer's premise for the purpose of service connection, service disconnection, operation, maintenance, repair and service restoration work that the Company may need to perform.

2. If additional resources are required to gain safe access to perform service establishment, disconnection, meter reading, or routine maintenance, due to an affirmative, wrongful, and/or criminal act by the Customer, the Company will be entitled to collect from the Customer all expenses incurred by the Company for additional resources including: investigation of access, all legal expenses, and court costs.

JK. Customer-Specific Information

Customer-specific information shall not be released without specific prior Customer authorization unless the information is requested by law enforcement or other public agency, or is requested by the Commission or its staff, or is reasonably required for legitimate account collection activities, or is necessary to provide safe and reliable service to the Customer. Such Customer authorization may be obtained electronically, in writing, or orally, as long as the oral authorization is recorded.

SECTION 8
PROVISION OF SERVICE

A. Company Responsibility

1. The Company will be responsible for the safe transmission and distribution of electricity until it passes the point of delivery to the Customer.

2. The Company will be responsible for maintaining in safe operating condition all meters, equipment and fixtures installed on the Customer's premises by the Company for the purpose of delivering electric service to the Customer. However, the Company will not be responsible for the condition of meters, equipment, and fixtures damaged or altered by the Customer.

3. The Company may, at its option, refuse service until the Customer has obtained all required permits and/or inspections indicating that the Customer's facilities comply with local construction and safety standards, including any applicable Company specifications.

4. The Company will determine, in its sole discretion, the type of service (including voltage and Point of Delivery) to be furnished for utilization by the Customer. This includes determinations involving: 1) requirements to take Primary Service and Metering; and 2) service voltage (including for any new on-site generation installations or generation retrofits at the Customer's premises).

B. Customer Responsibility

1. Each Customer will be responsible for maintaining in safe operating condition all Customer facilities on the Customer's side of the point of delivery.

2. Each Customer will be responsible for safeguarding all Company property installed in or on the Customer's premises for the purpose of supplying electric service to that Customer.

3. Each Customer will exercise all reasonable care to prevent loss or damage to Company property, excluding ordinary wear and tear. The Customer will be responsible for loss of or damage to Company property on the Customer's premises arising from neglect, carelessness, misuse, diversion, or tampering and will reimburse the Company for the cost of necessary repairs or replacements.

4. Each Customer will be responsible for payment for any equipment damage and/or estimated unmetered usage and all reasonable costs resulting from unauthorized breaking of seals, interfering, tampering or bypassing the Company meter.

5. Each Customer will be responsible for notifying the Company of any equipment failure identified in the Company's equipment.

SECTION 8
PROVISION OF SERVICE
(continued)

6. Each Customer will be responsible for informing the Company of, and meeting the Company's requirements regarding on-site or distributed generation (including distributed renewable resources and combined heat and power facilities) that the Customer or the Customer's agent intends to interconnect to the Company's transmission or distribution system. This includes compliance with all requirements contained within the Company's most current Interconnection Requirements for Distributed Generation, and the terms and conditions of the Company's Agreement for the Interconnection of Customer's Facility. Customer must also agree to enter into the Interconnection Agreement with the Company. Further, any interconnection must be in accordance with any applicable Commission regulation and order governing interconnection, as well as applicable laws.

7. The Customer, at his expense, may install, maintain and operate check-measuring equipment as desired and of a type approved by the Company, provided that this equipment will be installed so as not to interfere with operation of the Company's equipment. This is also provided that no electric energy will be remetered or submetered for resale to another or to others, except where such remetering will be done in accordance with the applicable orders of the Commission.

C. Continuity of Service

The Company will make reasonable efforts to supply a satisfactory and continuous level of service. However, the Company will not be responsible for any damage or claim of damage attributable to any interruption or discontinuation of service resulting from:

1. Any cause against which the Company could not have reasonably foreseen, or made provision for (*i.e* force majeure, see Subsection 8.E.);

2. Intentional service interruptions to make repairs or perform routine maintenance; or

3. Curtailment, including brownouts or blackouts.

D. Service Interruptions

1. The Company will make reasonable efforts to reestablish service within the shortest possible time when service interruptions occur.

2. In the event of a national emergency or local disaster resulting in disruption of normal service, the Company may, in the public interest, interrupt service to other Customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

SECTION 8
PROVISION OF SERVICE
(continued)

3. When the Company plans to interrupt service for more than four (4) hours to perform necessary repairs or maintenance, the Company will attempt to inform affected Customers at least twenty-four (24) hours in advance of the scheduled date and these repairs will be completed in the shortest possible time to minimize the inconvenience to the Customers of the Company.

4. The Commission will be notified of interruption in service affecting the entire system or any significant portion thereof. The interruption of service and cause will be reported by telephone to the Commission within four (4) hours after the responsible Company representative becomes aware of said interruption. A written report to the Commission will follow.

E. Interruption of Service and Force Majeure

1. The Company will make reasonable provision to supply a satisfactory and continuous electric service, but does not guarantee a constant or uninterrupted supply of electricity. The Company will not be liable for any damage or claim of damage attributable to any temporary, partial or complete interruption or discontinuance of electric service attributable to a force majeure condition as set forth in Subsections 8.E.4. and 8.E.5. or to any other cause which the Company could not have reasonably foreseen and made provision against, or which, in the Company's judgment, is necessary to permit repairs or changes to be made in the Company's electric generating, transmission, or distribution equipment, or to eliminate the possibility of damage to the Company's property or to the person or property of others.

2. Whenever the Company deems a condition exists that warrants interruption or limitation in the service being rendered, this limitation or interruption will not constitute a breach of contract and will not render the Company liable for damages suffered thereby or excuse the Customer from further fulfillment of the contract.

3. The use of electric energy upon the Customer's premises is at the risk of the Customer. The Company's liability will cease at the point where its facilities are connected to the Customer's wiring.

4. Neither the Company nor the Customer will be liable to the other for any act, omission, or circumstances (including, but not limited to, the Company's inability to provide electric service) occasioned by or in consequence of the following:

   a. flood, rain, wind, storm, lightning, earthquake, fire, landslide, washout or other acts of the elements;

   b. accident or explosion;

   c. war, rebellion, civil disturbance, mobs, riot, blockade or other act of the public enemy;

   d. acts of God;

   e. interference of civil and/or military authorities;

SECTION 8
PROVISION OF SERVICE
(continued)

f. strikes, lockouts, or other labor difficulties;

g. vandalism, sabotage, or malicious mischief;

h. usurpation of power, or the laws, rules, regulations, or orders made or adopted by any regulatory or other governmental agency or body (federal, state or local) having jurisdiction of any of the business or affairs of the Company or the Customer, direct or indirect;

i. breakage or accidents to equipment or facilities;

j. lack, limitation or loss of electrical or fuel supply; or

k. any other casualty or cause beyond the reasonable control of the Company or the Customer, whether or not specifically provided herein and without limitation to the types enumerated, and which by exercise of due diligence the Company or the Customer is unable to overcome.

5. A failure to settle or prevent any strike or other controversy with employees or with anyone purporting or seeking to represent employees will not be considered to be a matter within the control of the Company.

6. Nothing contained in this Section will excuse the Customer from the obligation of paying for electricity delivered or services rendered.

F. General Liability

1. Company will not be responsible for any third-party claims against Company that arise from Customer's use of Company's electric services, unless such claims are caused by the Company's willful misconduct or gross negligence.

2. Customer will indemnify, defend and hold harmless the Company (including the costs of reasonable attorney's fees) against all claims (including, without limitation, claims for damages to any business or property, or injury to, or death of, any person) arising out of any wrongful or negligent acts or omissions of the Customer, or the Customer's agents, in connection with the Company's service or facilities.

3. Except in the case of the Company's willful misconduct or gross negligence, ~~The liability of~~ the Company will not be liable to Customer or any other party for damages of any nature arising from errors, mistakes, omissions, interruptions, or delays of the Company, its agents, servants, or employees, in the course of, or related to, establishing, furnishing, rearranging, moving, terminating, or changing the service or facilities or equipment, except that for an interruption of service to a Customer, to the extent resulting from error, mistake, omission, interruption or delay by the Company, the Company's liability, if any, to the Customer -shall not exceed an amount equal to the charges for service applicable under the Company's Rates (calculated on a proportionate basis where appropriate) ~~to~~for the period of service interruption. ~~during which the error, mistake, omission, interruption or delay occurs, except if such damages are caused by the Company's willful misconduct or gross negligence.~~

SECTION 8
PROVISION OF SERVICE
(continued)

4. In no event will the Company be liable for any incidental, indirect, special, or consequential damages (including lost revenue or profits) of any kind whatsoever regardless of the cause or foreseeability thereof.

5. The Company will not be responsible in an occasion for any loss or damage caused by the negligence or wrongful act of the Customer or any of his agents, employees or licensees in installing, maintaining, using, operating or interfering with any electric facilities.

G. Construction Standards and Safety

The Company will construct all facilities in accordance with the provisions of the ANSI C2 Standards (National Electric Safety Code, 2007 edition, and other amended editions as are adopted by the ACC), the 2007 ANSI B31.1 Standards, the ASME Boiler and Pressure Vessel Code, and other applicable American National Standards Institute Codes and Standards, except for those changes the ACC makes or permits from time to time. In the case of conflict between codes and standards, the more rigid code or standard will apply.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

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

EXHIBIT
UNSE-21
ADMITTED

Rejoinder Testimony of

Denise A. Smith

on Behalf of

UNS Electric, Inc.

February 29, 2016

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DAS – RJ-1 Electric Demand for Appliances
DAS – RJ-2 Demand Monitor Charts
DAS – RJ-3 Plan of Administration ("POA") for the DSM adjustor

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Denise A. Smith. My business address is 88 E. Broadway Blvd., Tucson, Arizona 85702.

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

A. Yes.

Q. Which Commission Staff and/or Intervener testimony do you address in your Rejoinder Testimony?

A. I address the Surrebuttal Testimonies filed by Candrea Allen, Eric Van Epps and Thomas M. Broderick of the Utilities Division ("Staff") of the Arizona Corporation Commission ("Commission"); Cynthia Zwick on behalf of the Arizona Community Action Association ("ACAA"); and Jeff Schlegel on behalf of Southwest Energy Efficiency Project ("SWEEP").

II. RESPONSE TO REQUESTS FROM PARTIES REGARDING CUSTOMER EDUCATION

Q. How will the Company inform, educate and assist customers with understanding their demand charge and how to reduce their total electrical bill under a 3-part rate structure?

A. Several parties in this case have expressed a desire for customer education and programs around a 3-part rate structure. The specific witnesses I will address are Staff witness Thomas Broderick, Staff witness Eric Van Epps and SWEEP witness Jeff Schlegel. The Company is planning a multi-staged, multi-channel approach to supporting customers

according to their preferred communications channel of traditional paper mailing, electronic (email) delivery and telephonic Interactive Voice Response (IVR) system. In addition, in late 2016 the Company will be launching a customer application supporting mobile access to account related data and messaging on cellular or WiFi enabled Apple and Android devices. The full plan was attached to UNSE witness Dallas Dukes' Rebuttal testimony.

Supporting customers' understanding of a 3-part rate structure will require new tools and programming that leverage the Company's existing platforms and Energy Efficiency programming. The Company is currently evaluating both modifications to existing programs and tools, as well as new technologies specifically addressing one or more of the following: (1) the identification of a customer's peak demand, (2) the disaggregation of devices that contribute to a customer's peak demand, and (3) recommendations on how to conveniently modify electrical usage to minimize the customer's demand profile.

Q. What enhancements will the Company make to existing programming to support customers' understanding of 3-part rates?

A. All existing DSM programs and measures aid customers in reducing their energy usage including demand charges under 3-part rates including high efficiency Heating Ventilating and Air Conditioning (HVAC), lighting, trees and appliances. The following programs and measures will be specially leveraged to assist customers' understanding their demand:

Education & Outreach: The transition to 3-part rates will require new enhancements to the Company's education & outreach materials. Media updates, print material, workshop & classroom content, public presentations and e-learning tools will be

developed and implemented to assist customers in understanding their demand charge and how appliance management can help them reduce their demand profile.

Home Energy Calculator (https://www.uesaz.com/efficiency/tools/ezhome/)**:** this tool currently provides customers with a free, online and customized estimation of how they are using energy in their home. This tool may be leveraged by self-learners and also Company representatives directly supporting customers learning to disaggregate their monthly energy usage.

This type of tool will be used to create a new demand calculator with residential demand loads of various appliances and products averaged over an hour. The calculator will utilize the data prepared in Exhibit DAS-RJ-1.

Home Energy Reports: This program recently approved by the Commission will provide broad outreach through a customizable messaging platform built around educating customers on how to reduce their energy usage. Customized messages and recommendations can be targeted toward reducing demand in addition to consumption.

Q. What new programs and measures will assist customers with the implementation of 3-part rates?

A. The Company is reviewing a number of new DSM tools and technologies in anticipation of submitting a separate, timely DSM filing pending the approval of a 3-part rate structure. Most programs would include an incentive lowering the cost to the customer.

Smart Thermostats: This measure enables customers to optimize the operation of their air conditioning or Heat Pump which typically generates a customer's highest

demand load. Smart Learning Thermostats have demonstrated residential customer savings on cooling and heating costs. Smart algorithms outperform user programming by analyzing actual equipment and building performance data, weather data, occupancy and user inputs for customers who wish to manage their heating and cooling. Smart Thermostat applications also offer an engagement platform for utilities to communicate additional energy saving tips and operate demand response programming.

Advanced Meters and Data Presentment: The Company's Meter Data Management system currently captures and stores hourly residential interval data which is processed and available on a day-in-arrears basis. The Company is currently evaluating opportunities to present this data to customers through account management tools in a variety of useful formats including the real time availability of interval data.

Home Energy Monitoring Systems: Home Energy Monitoring systems continue to evolve towards cloud-based content and analytics. The Company is reviewing market ready technologies such as the Efergy Engage platform (https://engage.efergy.com/) as potential support solutions. This type of solution utilizes sensors to measure current for real time demand. The web portal and mobile application display customers' demand in an effortless and understandable manner. The display shows the customer's demand in real time, hourly, daily, weekly, and monthly. See DAS-RJ-2 for an example.

Smart Plugs: Smart Plugs are WiFi-enabled home appliance plugs that allow customers to manage their plugged in devices without having to touch them and to automate their home through smart platform engagement. The technology focuses on

controlling small appliances using 1800 watts or under, including lights, window air conditioners, fans, portable heaters, coffee makers, and home audio systems.

Demand Controllers: The Company is researching the potential option of hardwired demand control solution for residential load. Demand Controllers can be used in demand response and energy management applications. These controllers may be used for management and monitoring of HVAC compressors, water heaters, pool pumps, and other power circuits.

III. RESPONSE TO STAFF (Eric Van Epps)

Q. Please address Staff's witness Mr. Van Epps request for a Plan of Administration (POA) for the Demand Side Management surcharge adjustor.

A. The Company agrees that a POA is appropriate in this circumstance. UNS Electric's POA for the DSM surcharge is attached in Exhibit DAS-RJ-3. The POA is consistent with the Commission's Energy Efficiency Rules, A.A.C. R14-2-2401 to R14-2-2419. The POA addresses such items as allowable expenses, the true-up methodology, and the calculation of the adjustor mechanism. Schedules of the calculations are included as an attachment to the POA.

IV. RESPONSE TO STAFF (Candrea Allen)

Q. Please comment on Subsection 12.H. of the Rules and Regulations ("Rules")?

A. Staff initially did not recommend approval of UNS Electric's proposed language for Subsection 12.H. In Staff's Surrebuttal Testimony, Staff proposed that UNS Electric's proposed language should not apply to medical alert customers; it should apply to all other customers in lieu of disconnection of service. This program was not proposed to be

deployed for customers in general who do not pay their bills, it was meant for medical alert customers and inclement weather situations. Therefore, as we only see a value for this language for medical alert customers, and certain weather situations, UNS Electric will withdraw its request for approval of Subsection 12.H if all parties agree.

Q. Do you agree with Staff's recommendations regarding the Subsection 3.B.1.a. of the Rules?

A. Yes, we will agree to Staff's recommendation to leave the words, "more than" in Subsection 3.B.1.a. of the Rules.

V. RESPONSE TO ACAA

Q. Do you agree with the ACAA's recommendations to hold CARES customer harmless from deposits?

A. No, UNS Electric believes all customers should be treated the same with respect to deposits. UNS Electric currently does and will continue to work with customers who need help. I'm reaffirming the position held in my Rebuttal Testimony (page 4) filed January 19, 2016.

VI. RESPONSE TO SWEEP

Q. Do you agree with SWEEP's assessment that a mandatory demand charge will limit customers' options regarding how they control their bills?

A. No. To the contrary adding a demand component to the rate expands the opportunity for customers to manage their bills. As discussed by a number of witnesses, *customers who may not be able to reduce their volumetric consumption would now be rewarded for modifying their usage schedule to flatten their load profile*. DSM programs can be used

as a tool to accomplish the objective of reducing demand charges. Demand charges are an important step in preparing customers toward a better understanding of their electrical bill.

Q. Do you share SWEEP's concern that mandatory demand charges might disproportionately shift cost to lower usage customers?

A. No, the demand rate component of the bill is designed to improve the alignment of customer charges with the cost of service. Demand charges do not disproportionately allocate costs to lower usage customer; rather, they correctly allocate costs across the customer classes.

Q. Does the Company still agree with Staff that monies associated with Energy Efficiency should still to be collected through the DSM adjustor, a position opposed by SWEEP?

A. Yes, the Company remains in agreement with Staff that monies associated with Energy Efficiency should continue to be collected through the DSM adjustor. This retains the flexibility to manage the Energy Efficiency portfolio more dynamically in response to its annual goals versus awaiting a future rate case.

Q. Does this conclude your Testimony?

A. Yes, it does.

Exhibit DAS-RJ-1

DAS – RJ – 01

Electric Demand (Appliances and Equipment)

Item	Rated kW (Peak kW)	% 'on' each hour (Estimate)	Usage (kWh/Hr)
Refrigerators			
Energy Star Rated	0.225	30%	0.068
Old Unit - Not Energy Star Rated	0.7	30%	0.210
Freezers			
Energy Star Rated	0.225	30%	0.068
Old Unit - Not Energy Star Rated	0.7	30%	0.210
Large Appliances			
Oven	3.100	60%	1.860
Large Element	2.350	60%	1.410
Small Element	1.130	60%	0.678
Toaster Oven	1.500	50%	0.750
Microwave	1.500	30%	0.450
Dishwasher	1.100	60%	0.660
Water Cooler			
None	0.0000	60%	0.000
Water Cooler Cold	0.0050	60%	0.003
Water Cooler Hot&Cold	0.0100	60%	0.006
Laundry			
Clothes Washer	0.41	60%	0.246
Clothes Dryer	5.60	60%	3.360
Fans			
Ceiling Fan (no light)	0.06	100%	0.060
Portable Fan	0.06	100%	0.060
Water Heater			
Average for year	4.5	30.0%	1.350

Item	Rated kW (Peak kW)	% 'on' each hour (Estimate)	Usage (kWh/Hr)
Winter Heating			
Baseboard 1000 Watt	1.00	40%	0.400
Baseboard-1500 Watt	1.50	40%	0.600
Furnace Blower (Average)	0.50	40%	0.200
HP-1 ton New - Standard Efficiency	0.92	40%	0.369
HP-1 ton New - High Efficiency	0.75	40%	0.300
HP-1 ton-Old	1.33	40%	0.533
HP-2 ton New - Standard Efficiency	1.85	40%	0.738
HP-2 ton New - High Efficiency	1.50	40%	0.600
HP-2 ton-Old	2.67	40%	1.067
HP-2.5 ton New - Standard Efficiency	2.31	40%	0.923
HP-2.5 ton New - High Efficiency	1.88	40%	0.750
HP-2.5 ton-Old	3.33	40%	1.333
HP-3 ton New - Standard Efficiency	2.77	40%	1.108
HP-3 ton New - High Efficiency	2.25	40%	0.900
HP-3 ton-Old	4.00	40%	1.600
HP-3.5 ton New - Standard Efficiency	3.23	40%	1.292
HP-3.5 ton New - High Efficiency	2.63	40%	1.050
HP-3.5 ton-Old	4.67	40%	1.867
HP-4 ton New - Standard Efficiency	3.69	40%	1.477
HP-4 ton New - High Efficiency	3.00	40%	1.200
HP-4 ton-Old	5.33	40%	2.133
HP-5 ton New - Standard Efficiency	4.62	40%	1.846
HP-5 ton New - High Efficiency	3.75	40%	1.500
HP-5 ton-Old	6.67	40%	2.667
Central Resistance-<1200 sqft	5.00	40%	2.000
Central Resistance-1200-1799 sqft	7.50	40%	3.000
Central Resisitance-1800-2599 sqft	15.00	40%	6.000
Central Resisitance->2600 sqft	20.00	40%	8.000

Item	Rated kW (Peak kW)	% 'on' each hour (Estimate)	Usage (kWh/Hr)
Cooling Units			
AC-1 ton New - Standard Efficiency	0.92	50%	0.462
AC-1 ton New - High Efficiency	0.75	50%	0.375
AC-1 ton-Old	1.33	50%	0.667
AC-2 ton New - Standard Efficiency	1.85	50%	0.923
AC-2 ton New - High Efficiency	1.50	50%	0.750
AC-2 ton-Old	2.67	50%	1.333
AC-2.5 ton New - Standard Efficiency	2.31	50%	1.154
AC-2.5 ton New - High Efficiency	1.88	50%	0.938
AC-2.5 ton-Old	3.33	50%	1.667
AC-3 ton New - Standard Efficiency	2.77	50%	1.385
AC-3 ton New - High Efficiency	2.25	50%	1.125
AC-3 ton-Old	4.00	50%	2.000
AC-3.5 ton New - Standard Efficiency	3.23	50%	1.615
AC-3.5 ton New - High Efficiency	2.63	50%	1.313
AC-3.5 ton-Old	4.67	50%	2.333
AC-4 ton New - Standard Efficiency	3.69	50%	1.846
AC-4 ton New - High Efficiency	3.00	50%	1.500
AC-4 ton-Old	5.33	50%	2.667
AC-5 ton New - Standard Efficiency	4.62	50%	2.308
AC-5 ton New - High Efficiency	3.75	50%	1.875
AC-5 ton-Old	6.67	50%	3.333
EvapCooler-<1200 sqft	0.34	100%	0.34
EvapCooler-1200-1799sqft	0.46	100%	0.46
EvapCooler-1800-2599sqft	0.65	100%	0.65
EvapCooler->2600sqft	0.98	100%	0.98
MasterCool - Average Size	1.30	100%	1.30
Window AC-1.5 ton –New	1.50	50%	0.75
Window AC-1.5 ton- Old	2.00	50%	1.00
Window AC-1 ton – New	1.00	50%	0.50
Window AC-1 ton – Old	1.33	50%	0.67

Item	Rated kW (Peak kW)	% 'on' each hour (Estimate)	Usage (kWh/Hr)
Miscellaneous			
Electronic Air Cleaner	0.05	100%	0.05
Hair Dryer	0.71	100%	0.71
Humidifier	0.011	100%	0.01
Iron	1.1	60%	0.66
Rechargable power tools	0.018	60%	0.01
Slow cooker	0.2	100%	0.20
Toaster	1.1	100%	1.10
Vacuum	0.542	100%	0.54
Well pump	0.725	100%	0.73
Aquarium equipment	0.024	100%	0.02
Oxygen Conventrator	0.4	100%	0.40
Phantom Loads	0.0500	100%	0.050
Coffee Maker	1.000	30%	0.300
Deep Fryer	1.000	80%	0.800
Office Equipment			
Desktop Computer and Monitor (On)	0.245	100%	0.245
Computer & Monitor (Sleep Mode)	0.01	100%	0.010
Laptop	0.045	100%	0.045
Notebook computer	0.025	100%	0.025
Inkjet Printer	0.013	100%	0.013
Multi-Function Printer	0.018	100%	0.018
Pool, Spa or Fountain Pump			
None	0	100%	0.000
1/2 hp	0.65	100%	0.650
3/4 hp	0.84	100%	0.840
1 hp	1.2	100%	1.200
1 1/2 hp	1.5	100%	1.500
2 hp	2.1	100%	2.100
1 hp -Variable Spd	0.36	100%	0.360
1 1/2 hp -Variable Spd	0.45	100%	0.450

2 hp -Variable Spd	0.63	100%	0.630

Item	Rated kW (Peak kW)	% 'on' each hour (Estimate)	Usage (kWh/Hr)
Televisions/Stereo			
Plasma TV 42'	0.27	100%	0.270
Plasma TV 50"-56"	0.34	100%	0.340
Stereo System	0.033	100%	0.033
TV-analog < 40"	0.086	100%	0.086
TV-analog > 40"	0.156	100%	0.156
TV-ED/HD <40"	0.15	100%	0.150
TV-ED/HD >40"	0.234	100%	0.234
TV-LCD	0.15	100%	0.150
TV-Set-up box	0.02	100%	0.020
Cable/Gaming Systems			
HD-DVR	0.017	100%	0.017
HD-Cable Box	0.14	100%	0.140
Router/Cable modem	0.006	100%	0.006
Xbox	0.07	100%	0.070
Xbox 360	0.165	100%	0.165
Play Station 2	0.03	100%	0.030
Wii	0.0205	100%	0.021
CD Player	0.007	100%	0.007
Spa Heater			
None	0	0%	0.000
Spa Htr Summer- Covered	5.0	10%	0.500
Spa Htr Summer - No Cover	5.0	15%	0.750
Spa Htr Winter -Covered	5.0	35%	1.750
Spa Htr Winter - No Cover	5.0	55%	2.750

Item	Rated kW (Peak kW)	% 'on' each hour (Estimate)	Usage (kWh/Hr)
Winter Heating			
Baseboard 1000 Watt	1.00	40%	0.400
Baseboard-1500 Watt	1.50	40%	0.600
Furnace Blower (Average)	0.50	40%	0.200
HP-1 ton New - Standard Efficiency	0.92	40%	0.369
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EvapCooler-1200-1799sqft	0.46	100%	0.46
EvapCooler-1800-2599sqft	0.65	100%	0.65
EvapCooler->2600sqft	0.98	100%	0.98
MasterCool - Average Size	1.30	100%	1.30
Window AC-1.5 ton -New	1.50	50%	0.75
Window AC-1.5 ton- Old	2.00	50%	1.00

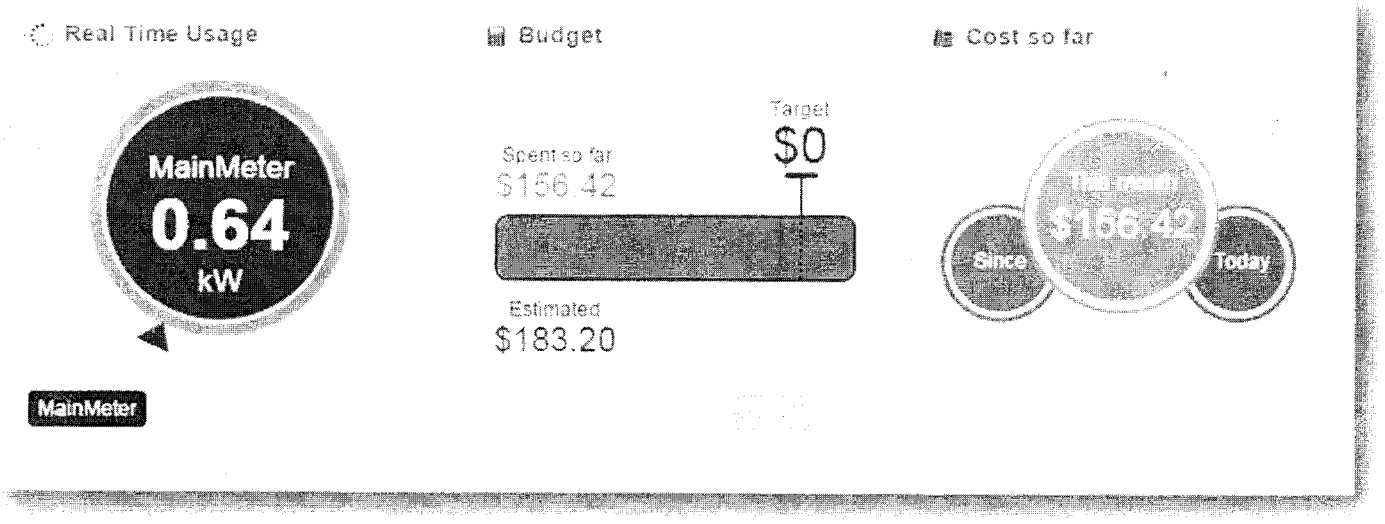
Window AC-1 ton - New	1.00	50%	0.50
Window AC-1 ton - Old	1.33	50%	0.67

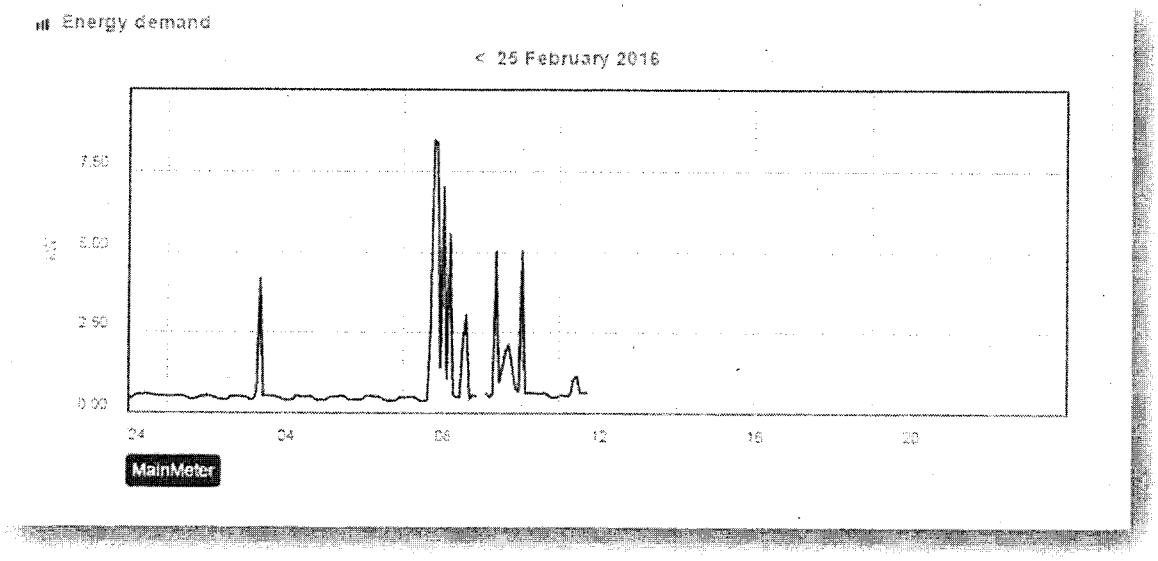
Exhibit DAS-RJ-2

DAS – RJ – 02

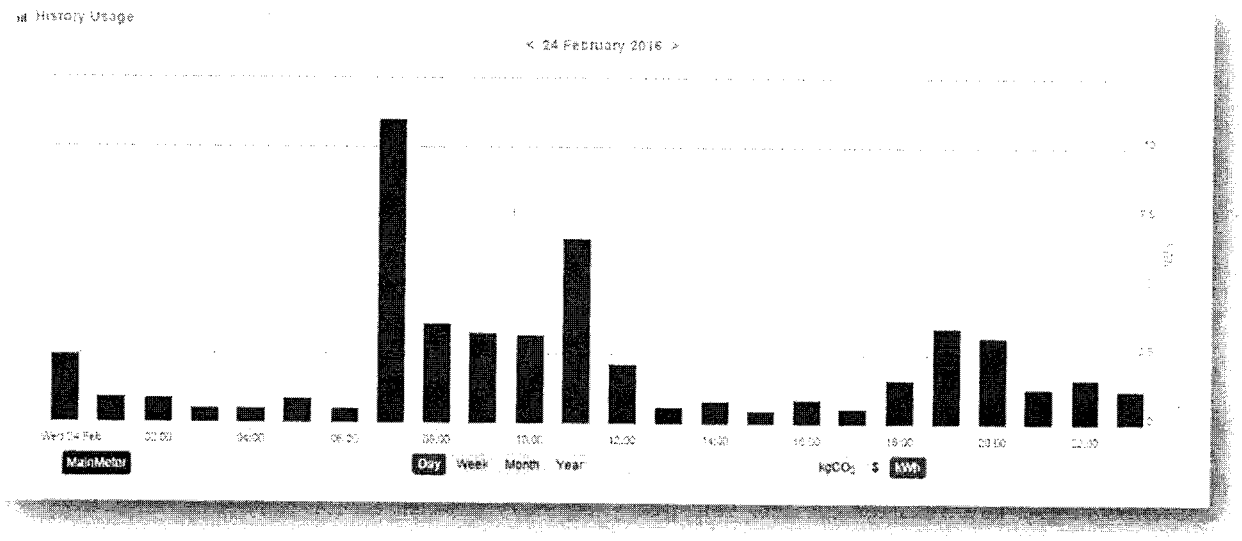
Demand Monitor

Allows customers to monitor their home energy use in real-time through your computer and mobile devices.

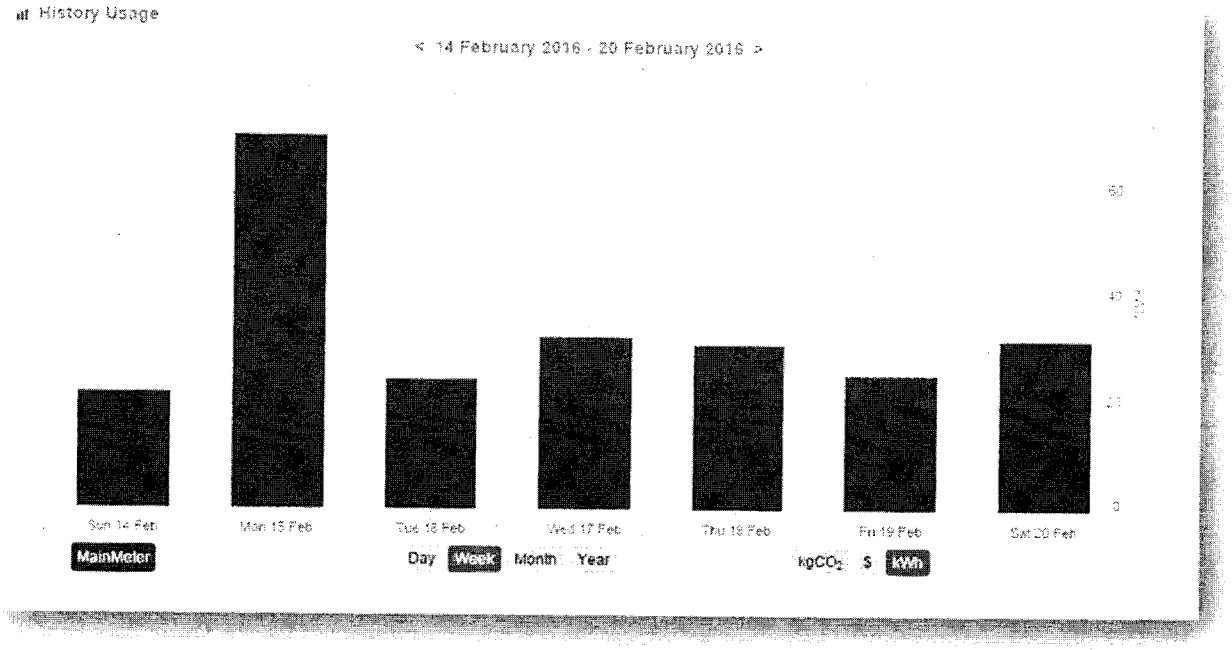




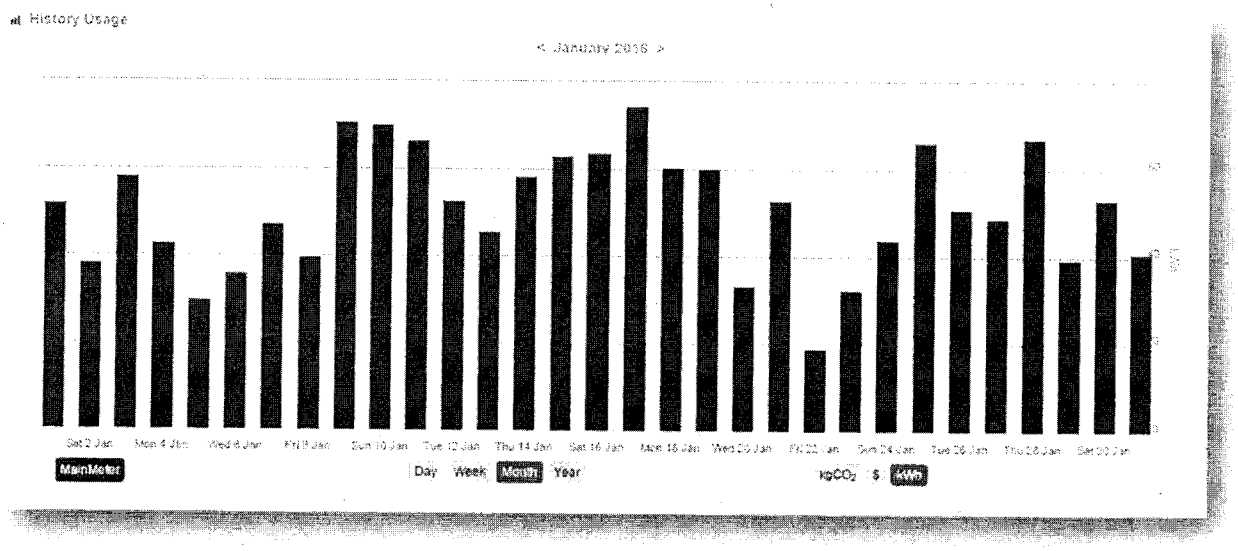
History – Hourly Usage



History – Daily for the Week



History – Daily for the Month



History – Monthly for the Year

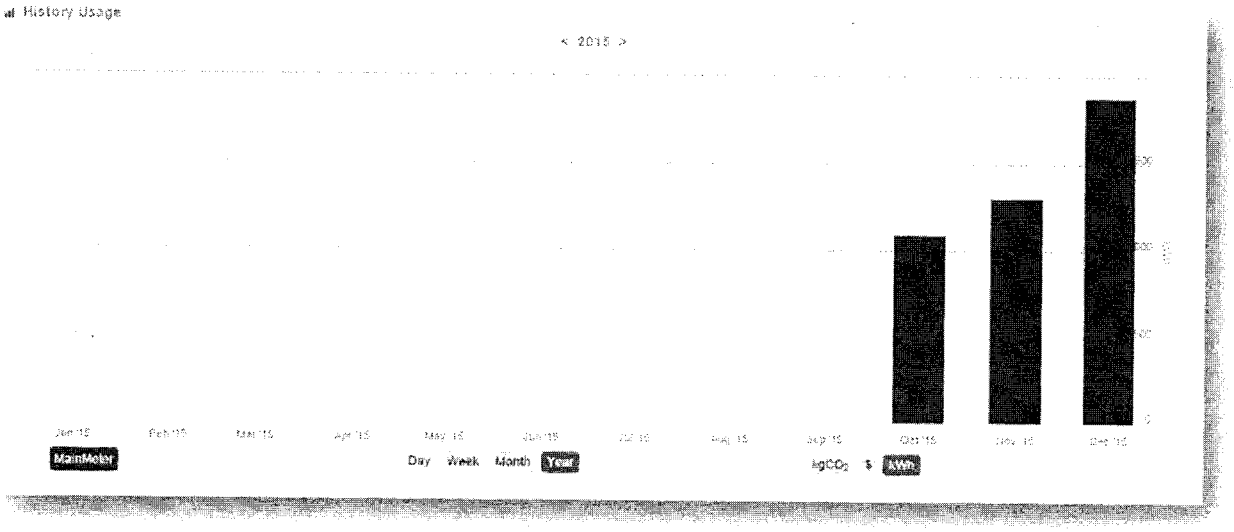


Exhibit DAS-RJ-3

UNS Electric, Inc.
Demand Side Management Adjustor Charge
Plan of Administration

Table of Contents

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6. Determination of True-up (Carry Over) 4
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1. General Description

This document describes the plan of administration for the Demand Side Management Adjustor Charge ("DSMAC") approved for UNS Electric, Inc. ("UNS Electric" or "Company") by the Arizona Corporation Commission ("ACC") in Decision No. 74235 (December 31, 2013). The DSMAC provides for the recovery of Demand Side Management ("DSM") program costs, including energy efficiency and demand response programs, and energy efficiency performance incentives. The DSMAC is applied to customer's bills as a monthly kilowatt-hour charge for Residential customers and on a percentage of bill basis for non-residential customers.

2. Definitions

A. "Adjustment charge" means a Commission-approved provision in an affected utility's rate schedule allowing the affected utility to increase and decrease a certain rate or rates, in an established manner, when increases and decreases in specific costs are incurred by the affected utility.
B. "DSM" means demand-side management, the implementation and maintenance of one or more DSM programs.
C. "DSM program" means one or more DSM measures provided as part of a single offering to customers.
D. "DSM tariff" means a Commission-approved schedule of rates designed to recover an affected utility's reasonable and prudent costs of complying with the Energy efficiency standard.
E. "Energy efficiency" means the production or delivery of an equivalent level and quality of end-use electric service using less energy, or the conservation of energy by end-use customers.
F. "Energy efficiency standard" means the reduction in retail energy sales, in percentage of kWh, required to be achieved through an affected utility's approved DSM programs as prescribed in R14-2-2404.

G. "Energy savings" means the reduction in a customer's energy consumption directly resulting from a DSM program, expressed in kWh.
H. "Net benefits" means the incremental benefits resulting from DSM minus the incremental costs of DSM.
I. "Program costs" means the expenses incurred by an affected utility as a result of developing, marketing, implementing, administering, and evaluating Commission-approved DSM programs.

3. ***Filing and Procedural Deadlines***

UNSE wishes to retain flexibility in filing EE Implementation Plans and modifications to the DSMAC. Changes to the EE Implementation Plans will be filed with the Commission in accordance with EE Standards R14-2-2405(A) shown below.

> *"Except as provided in R14-2-2418, on June 1 of each odd year, or annually at the election of each affected utility, each affected utility shall file with Docket Control, for Commission review and approval, an implementation plan describing how the affected utility intends to meet the energy efficiency standard for the next one or two calendar years, as applicable, except that the initial implementation plan shall be filed within 30 days of the effective date of this Article."*

Requested changes to the DSMAC will be filed with the Commission in accordance with the following sections of the EE Standards:

Implementation Plans R14-2-2405(B)(2):

> *"Except for the initial implementation plan, which shall describe only the next calendar year, a description of how the affected utility intends to comply with this Article for the next two calendar years, including an explanation of any modification to the rates of an existing DSM adjustment mechanism or tariff that the affected utility believes is necessary."*

Implementation Plans R14-2-2405(B)(5):

> *"A DSM Tariff filing complying with R14-2-2406(A) or a request to modify and reset an adjustment mechanism complying with R14-2-2406(C), as applicable;"*

DSM Tariffs R14-2-2406(C)

> *"If an affected utility has an existing adjustment mechanism to recover the reasonable and prudent costs associated with implementing DSM programs, the affected utility may, in lieu of making a tariff filing under subsection (A), file a request to modify and reset its adjustment mechanism by submitting the information required under subsections (A)(1) and(3)".*

Adjustor Reset and Reporting Requirements Decision No. 72447 (January 20, 2012)

> *"IT IS FURTHER ORDERED that, in any year during which the Company does not file an Implementation Plan, or does not address the DSM adjustor reset within its Implementation Plan, an adjustor reset application should be filed separately, no later than April 1."*

If UNSE chooses not to file an EE Implementation Plan in the even number year, UNSE may file new programs, measures or budget changes in a supplemental filing to the current EE Implementation Plan filing if UNSE or the Commission determines a change or addition is critical to the Company's ability to meet obligations under the EE Standard.

4. ***Rate Schedule Applicability:***

The DSMS shall be applied monthly to every customer unless exempted by order of the Commission. Currently there are no exemptions for UNS Electric.

5. ***Allowable Costs:***

Unless otherwise ordered by the Commission, UNSE includes allowable program costs for all approved programs and the Commission approved performance incentives in the DSMAC calculation. Allowable costs include but are not limited to the following:

A. Program Costs ("PC")
UNSE includes all allowable expenses in the DSMAC calculation. Allowable expenses include, but are not limited to: program development, implementation, promotion, administrative and general, training and technical assistance, marketing and communications, evaluation costs, monitoring and metering costs, advertising, educational expenditures, customer incentives, research and development, data collection (such as end-use), tracking systems, self-direction costs, measurement evaluation and research ("MER"), demonstration facilities and all other activities required to design and implement cost-effective DSM programs (energy efficiency and demand response) that are approved by the Commission in the Energy Efficiency Implementation Plan ("EEIP"). For those DSM programs that generate revenue, the revenue, if any, will be credited back to the DSMAC. Unrecovered fixed costs will not be recoverable through the DSMAC.

B. Wages and Salaries
During a general rate case UNSE includes wages or salaries for employees working to plan, implement, or manage EE Programs in UNSE base rate calculations. If, due to regulatory lag between rate cases, actual labor dollars for employees working to plan, implement, or manage EE Programs exceed the amount approved in rate base, the incremental labor dollars will be allocated to the calculation of DSMS.

C. Legal Expenses
Legal expenses for outside counsel working on DSM projects will be included as a recoverable DSM expense. Legal expenses for outside counsel is charged to a general DSM fund and then spread across all programs. Legal expenses from inside counsel are covered in item B above.

D. Reporting Requirements
Reporting Requirements for the EEIP are outlined in R-14-2-2409 of the EE Standard. Annual and Semi-Annual reporting details include no requirement for addressing carry-over funds. Carry-over funds are only used when requesting an adjustment to the DSMAC.

E. Performance Incentives ("PI")

UNSE includes a Commission approved percentage share of the economic benefits (benefits minus costs) from approved energy-efficiency programs in the DSMAC calculation but the total dollar amount is capped at the Commission approved $/kWh.

PI as % of Net Benefits	Capped at $/kWh
8%	$0.0125

The calculation of UNSE Performance Incentive will use the net benefits (total benefits minus total costs) derived from all Commission approved DSM programs unless otherwise ordered by the Commission. At this time, the Commission allows UNSE to include net benefits from all Commission approved programs in this calculation.

If the allowed % of net benefits exceeds the results from multiplying total kWh savings times $0.0125, the PI will be capped at the $/kWh calculation.

6. ***Determination Of True-Up (Carry Over):***

UNSE makes significant effort to estimate the allowable budgeted costs for EE programs, the PI and the DSMAC revenue collection but because these items are only a prediction of what might occur in the future it is impossible to be 100% accurate. Therefore it is possible for UNSE to either over-collect or under-collect allowable costs through the DSMAC.

Using the actual values at the end of each year, UNSE develops a True-Up (TU) balancing account (allowable expenses minus amount collected). This balance will include past period PC, PI and

DSMAC revenue collection accruals as of December 31st of the previous year. Past period PC and PI, past period DSMAC revenue, and the TU balancing account computation will be provided annually in Schedule 2 of the DSMAC calculations.

The True-Up (TU) calculation for the new DSMAC will be based on the difference in the total allowable expenses and the amount in the TU balancing account. In the event that PC or PI are more or less than DSMAC revenues collected, the over or under collection will be subtracted from or added to the DSMAC calculation in the subsequent period.

7. ***Determination Of The Adjustor Charge:***

UNSE may file a revised DSMAC with supporting documentation by June 1st of each year when UNSE files a revised EEIP. Or UNSE may file a request for a DSMAC adjustment in a supplemental filing by April 1st. The DSMAC will be calculated by projecting PC and PI for the upcoming year, adjusted by the over or under collection of previous periods. This calculation will be provided in the annual DSMAC calculation on Schedule 1.

The DSMAC for purposes of recovering PC and PI under the DSM Program will be developed based on the following formula:

$$\text{DSMAC} = \underline{\text{PC} + \text{PI} + \text{TU}}$$

Sales

Where:

PC	=	Program Costs as defined in section 5(A) forecast for the upcoming year.
PI	=	Performance Incentives as defined in section 5(E) forecast for the upcoming year.
TU	=	Any "true-up" balance as defined in section 6.
Sales previous	=	Energy (kWh) sales under applicable electric rate schedules for the calendar year.
Adjustor Period	=	The 12 month period beginning for which the adjustor will be in effect.

The DSMAC for all customers will be calculated as a $/kWh charge. To calculate the $/kWh that will be applied to all customer bills, the recoverable costs (Program cost plus Incentives) shall be divided by the total retail sales (kWh) from all applicable customers. For billing purposes, the DSMAC will appear on the customer bills under the "Green Energy Charge".

8. Review Process:

The proposed DSMAC for use during a specific Adjustor Period will be calculated as shown in Schedule 1. UNSE may file an updated adjustor charge each year with its EEIP or through a supplemental filing by April 1st as outlined R-14-2-2409 of the EE Standard. If approved by the Commission, changes in the DSMAC will be retroactive to the first day of January for the filing year.

9. Schedules

- Schedule 1: DSM Calculation
- Schedule 2: UNSE Operating Revenue
- Schedule 3: Surcharge Summary

SCHEDULE 1

UNSE Existing Rule Option Rate

Line	Class	Column A 20XX Retail Revenue ($)	Column B 20XX Retail Sales (kWh)	Column C EE Proposed Revenue by class (Per kWh) with Proposed Budget
1	Residential	UNSE OpRev, Column E, Line 13	UNSE OpRev, Column C, Line 13	Column B, Line 1 * Column A, Line 12
2	Commercial	UNSE OpRev, Column E, Line 27	UNSE OpRev, Column C, Line 27	Column B, Line 2 * Column A, Line 12
3	Industrial	UNSE OpRev, Column E, Line 35	UNSE OpRev, Column C, Line 35	Column B, Line 3 * Column A, Line 12
4	Mining	UNSE OpRev, Column E, Line 40	UNSE OpRev, Column C, Line 40	Column B, Line 4 * Column A, Line 12
5	Other	UNSE OpRev, Column E, Line 48	UNSE OpRev, Column C, Line 48	Column B, Line 5 * Column A, Line 12
6	Total	Sum Column A, Lines 1:5	Sum Column B, Lines 1:5	Sum Column C, Lines 1:5

		Proposed Budget & Surcharge	**Budget Collection with Current Surcharge**
7	20XX Total DSM $ Jan - Dec 20XX	2016 EEIP, Table 1.2, Column 2, Line 2	UNSE OpRev Column D, Line 52 * .0015
8	True-up	Surcharge Summary Column E, Line 10	NA
9	20XX Performance Incentive	Surcharge Summary Column B, Line 8	NA
10	Total 20XX DSM Recovery	Sum Column A, Lines 7:9	Sum Column C, Lines 7:9
11	$ / kWh Residential	Round Column A, Line 10/Column B, Line 6,4	Round Column C, Line 10/UNSE OpRev Column D, Line 52

SCHEDULE 2

UNSE Rev Sum -- YTD

UNS Electric, Inc
Revenue Summary Report - Year-to-Date
DEC-XX
XX-JAN-20XX

Line	Final	Column A Customers DEC-XX	Column B Customers DEC-XX	Column C KWH DEC-XX	Column D KWH DEC-XX	Column E Revenue DEC-XX	Column F Revenue DEC-XX
	Retail Sales:						
1	**Residential:**						
2	**5098 Res Unbilled Revenue**	0	0	0	0	0	0
3	**5701 Santa Cruz Res**	0	0	0	0	0	0
4	**5702 RES-01 CARES**	0	0	0	0	0	0
5	**5703 R-01 Residential Electric**	0	0	0	0	0	0
6	**5704 Res-01 CARES Medical**	0	0	0	0	0	0
7	**5707 Small Gen Svc**	0	0	0	0	0	0
8	**5718 Dusk to Dawn Lgtng Svc**	0	0	0	0	0	0
9	**5725 R-01 Bright Community Sol**	0	0	0	0	0	0
10	**5726 Res UNSE Super Peak TOU**	0	0	0	0	0	0
11	**5769 RES-01-TOU**	0	0	0	0	0	0
12							
13	**Residential**	0	0	0	0	0	0
14	**Commercial:**						
15	**5298 Com Unbilled Revenue**	0	0	0	0	0	0
16	**5705 Santa Cruz Small Gen Svc**	0	0	0	0	0	0
17	**5707 Small Gen Svc**	0	0	0	0	0	0
18	**5713 Lrg Gen Svc**	0	0	0	0	0	0
19	**5714 Lrg Gen Svc TOU**	0	0	0	0	0	0
20	**5717 Interruptible Pwr Svc**	0	0	0	0	0	0
21	**5718 Dusk to Dawn Lgtng Svc**	0	0	0	0	0	0

22	**5770 SGS-10-TOU**	0	0	0	0	0	0
23	**5771 LGS-TOU-N**	0	0	0	0	0	0
24	**5781 General Service SGS-10 Br**	0	0	0	0	0	0
25	**5785 Large General Service LGS**	0	0	0	0	0	0
26							
27	**Commercial**	0	0	0	0	0	0
28	**Industrial:**						
29	**5348 Ind Unbilled Revenue**	0	0	0	0	0	0
30	**5709 Lrg Pwr Svc - Dist**	0	0	0	0	0	0
31	**5712 Lrg Pwr Svc - Trans TOU**	0	0	0	0	0	0
32	**5772 LPS-TOU (<69)**	0	0	0	0	0	0
33	**5773 LPS-TOU (>=69)**	0	0	0	0	0	0
34							
35	**Industrial**	0	0	0	0	0	0
36	**Mining:**						
37	**5398 Mining Unbilled Revenue**	0	0	0	0	0	0
38	**5719 Lrg Pwr Svc - Mining**	0	0	0	0	0	0
39							
40	**Mining**	0	0	0	0	0	0
41	**Other:**						
42	**5448 Pub St Lt Unbilled Rev**	0	0	0	0	0	0
43	**5705 Santa Cruz Small Gen Svc**	0	0	0	0	0	0
44	**5707 Small Gen Svc**	0	0	0	0	0	0
45	**5713 Lrg Gen Svc**	0	0	0	0	0	0
46	**5718 Dusk to Dawn Lgtng Svc**	0	0	0	0	0	0
47							
48	**Other**	0	0	0	0	0	0
49	**Add: REST & DSM**	0	0	0	0	0	0
50	**Add: LFCR**	0	0	0	0	0	0

51						
52 **Total Retail Sales**	0	0	0	0	0	0

(1) Represents incremental revenue from sale of Bright Community Solar blocks to customers included in other rates.

SCHEDULE 3

Line		Column A	Column B	Column C	Column D	Column E
	UNSE Historical DSM Expenses vs Surcharge Balance					
	Year	**DSM Expenses**	**Performance Incentive (Collected Following Year)**	**DSMS Collection**	**Annual Over(+)/Under(-) Collected**	**Cumulative Over(+)/Under(-) Collected**
1	**2008**					
2	**2009**					
3	**2010**					
4	**2011**	$0	$0	$0	$0	$0
5	**2012**	$0	$0	$0	$0	$0
6	**2013**	$0	$0	$0	$0	$0
7	**2014**	$0	$0	$0	$0	$0
8	**2015**	$0	$0	$0	$0	$0
9	**2016**					

	UNSE Forecasted DSM Expenses vs. Surcharge Balance					
	Year	**DSM Expenses (Forecasted)**	**Performance Incentive (Collected Following Year)**	**DSMS Collection (Forecasted)**	**Annual Over(+)/Under(-) Collected**	**Cumulative Over(+)/Under(-) Collected**
10	**2016**	2016 EEIP, Table 1.2, Column 2, Line 2	Column B, Line 8	UNSE OpRev Column C, Line 52 X DSM Calculation Column A, Line 12	Sum(Column A, Line 10: Column C, Line 10)	Column E, Line 8 + Column D, Line 10
11	**2017**	$0	$0	$0	$0	$0
12	**2018**	$0	$0	$0	$0	$0

Totals	**Sum Column A, Lines 4:9 + Sum Column A, Lines 10:12**	**Sum Column B, Lines 4:9 + Sum Column B, Lines 10:12**	**Sum Column C, Lines 4:9 + Sum Column C, Lines 10:12**	**Sum Column D, Lines 4:9 + Sum Column D, Lines 10:12**	**Sum Column E, Lines 4:9 + Sum Column E, Lines 10:12**

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-_____

EXHIBIT
UNSE-22
admitted

Direct Testimony of

Ann E. Bulkley

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 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.

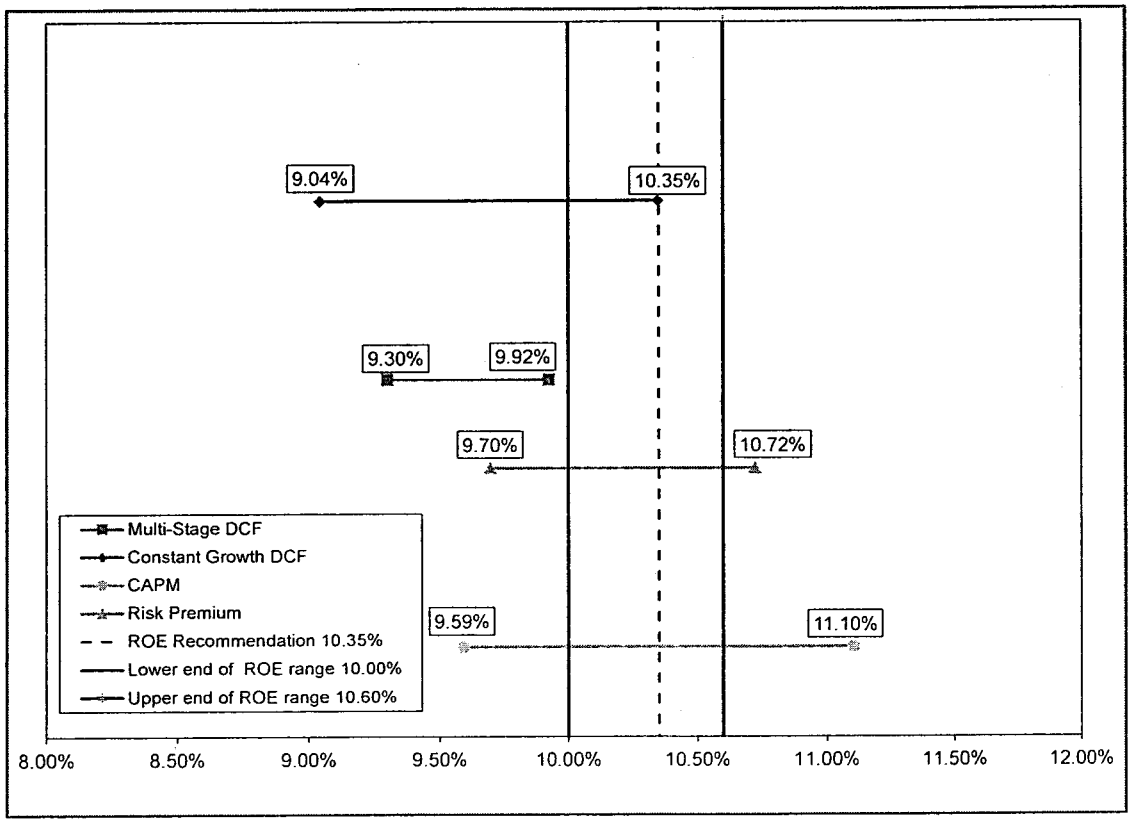
[2] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944); *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923).

- 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

---

[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

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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

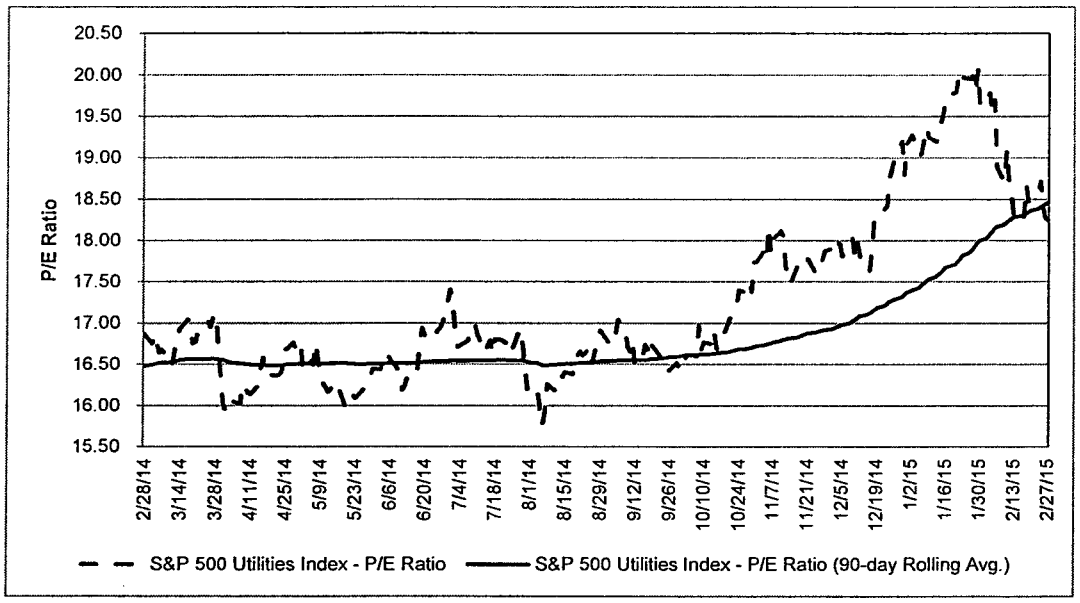
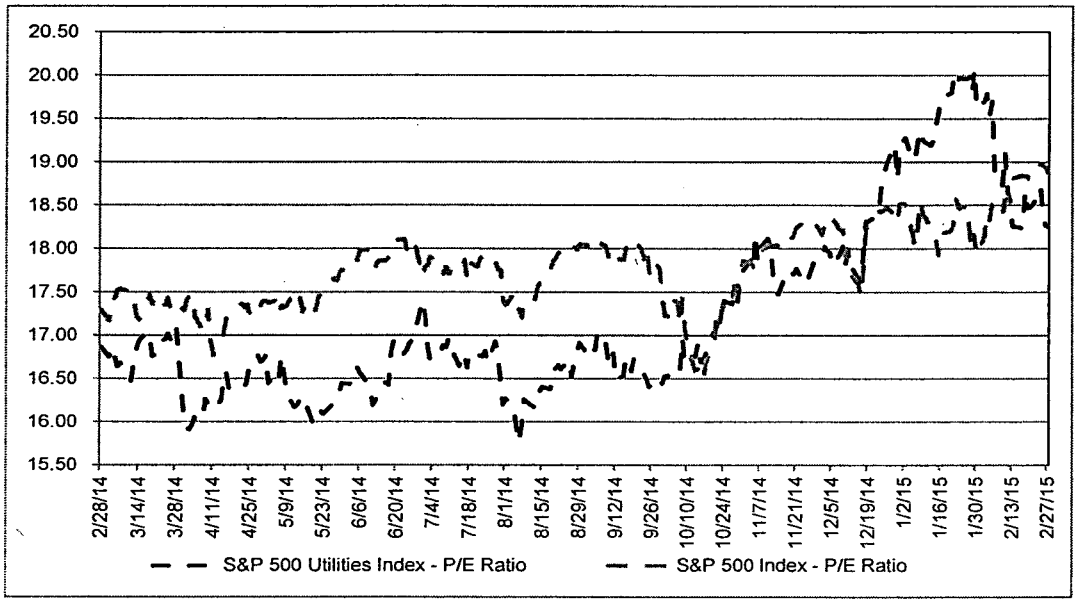


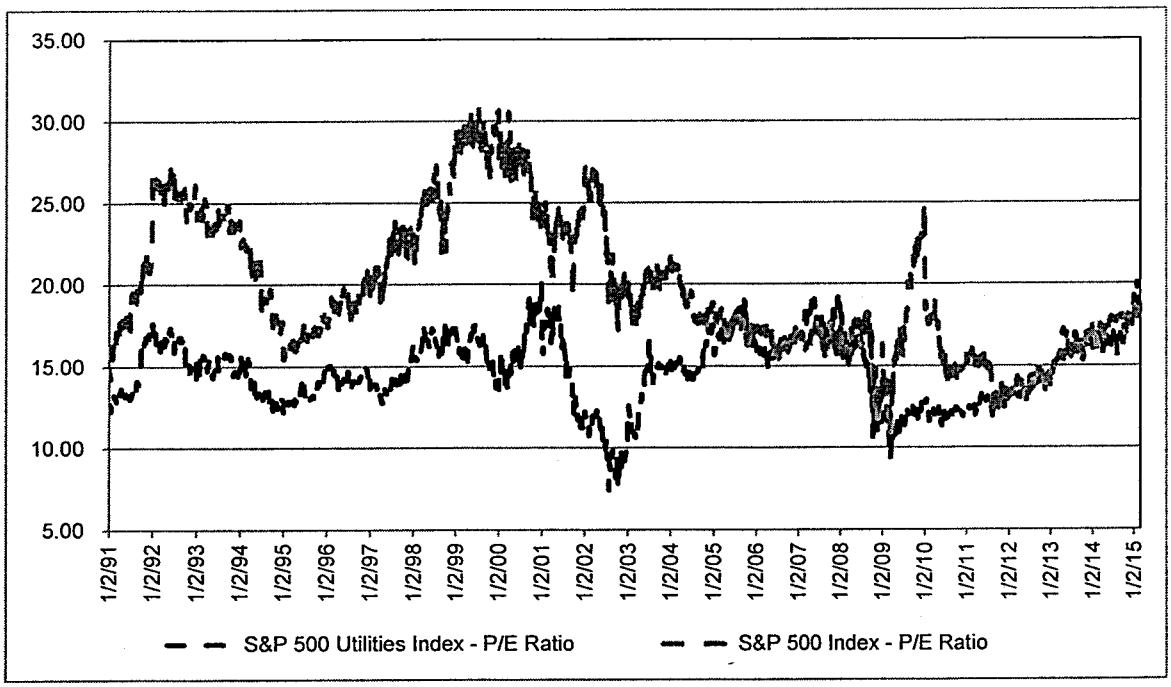
Chart 3: S&P Utilities Index vs. S&P 500 Index P/E Ratio



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:

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

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:

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

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

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[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%

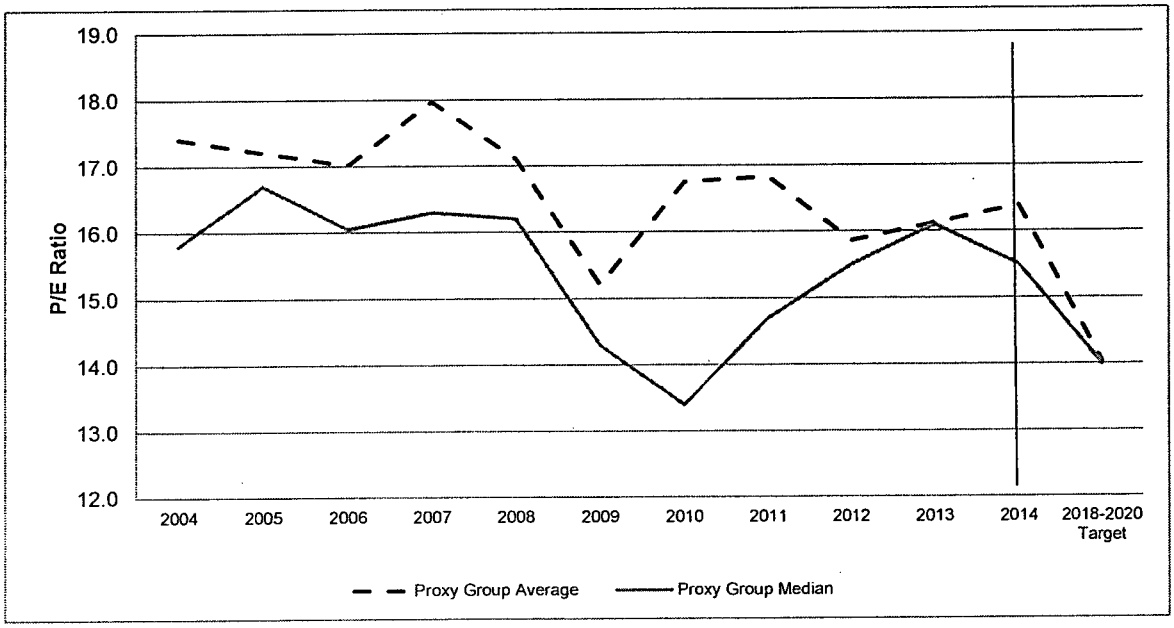
Q. How did you calculate the range of results for the Constant Growth and Multi-Stage DCF Models?

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.

[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)

[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.

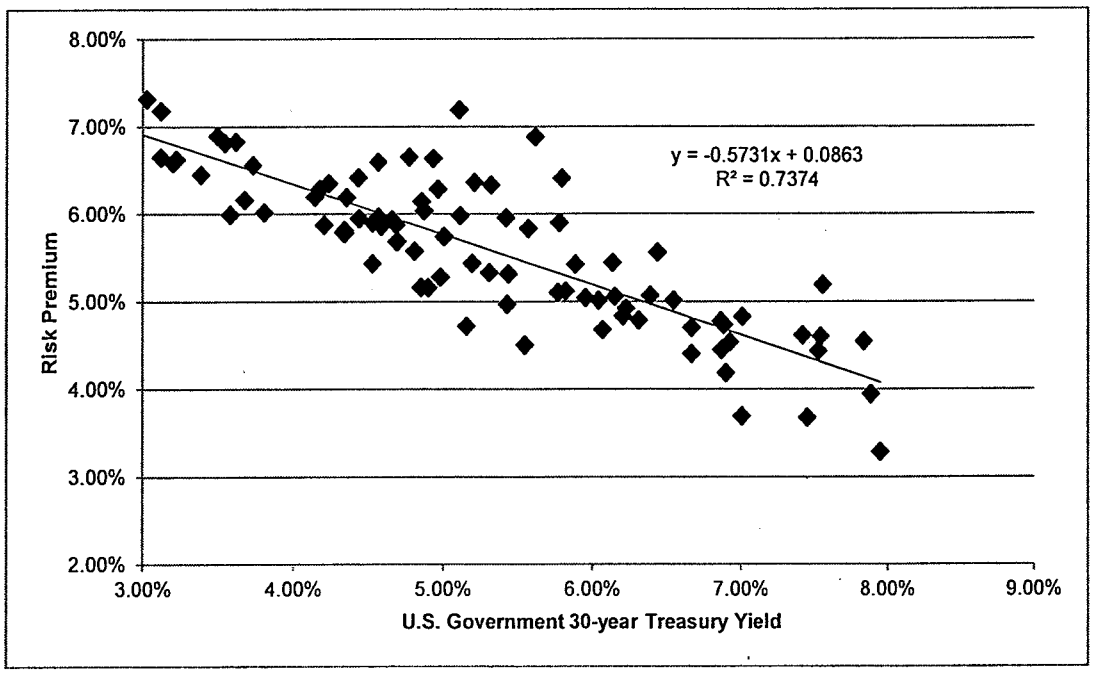
a = intercept term

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]

[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

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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

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[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

[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

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	$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] Risk-Free Rate	[5] Average Beta	[6] Market Risk Premium	[7] 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%
El 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

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.
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%

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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.
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%

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.
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%

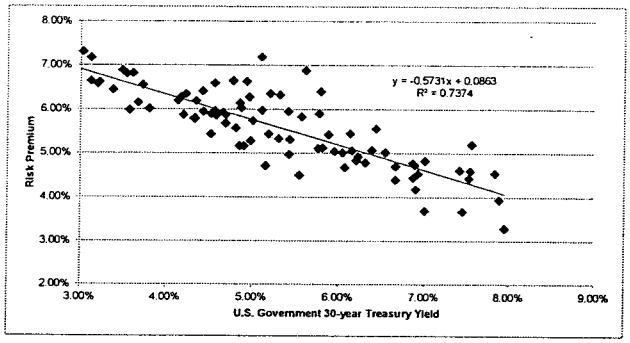
Notes:

[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] Average Authorized Electric ROE	[2] 30-year U.S. Treasury Bond	[3] 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] S&P Rank	[2] 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
						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])

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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

EXHIBIT
UNSE-23
admitted

Rebuttal Testimony of

Ann E. Bulkley

on Behalf of

UNS Electric, Inc.

January 19, 2016

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- AEB-R-1 Constant DCF
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- AEB-R-12 RP Excl. Settled

I. INTRODUCTION

Q. Please state your name and business address.

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

Q. On whose behalf are you submitting this testimony?

A. I am submitting this testimony on behalf of UNS Electric, Inc. ("UNS Electric" or the "Company").

Q. Did you previously submit testimony in this proceeding?

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

Q. What is the purpose of your Rebuttal Testimony?

A. The purpose of my Rebuttal Testimony is to respond to the cost of capital issues within the Direct Testimonies of Mr. Elijah Abinah on behalf of the Utilities Division Staff (the "Staff") of the Arizona Corporation Commission (the "Commission"), Mr. Robert B. Mease on behalf of the Residential Utility Consumer Office ("RUCO"), Dr. J. Randall Woolridge on behalf of The Alliance for Solar Choice ("TASC"), and Mr. Steve W. Chriss on behalf of Wal-Mart Stores, Inc. (collectively, the "Opposing ROE Witnesses").

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

A. Yes. My updated analysis and recommendations are supported by the data presented in Exhibits AEB-R-1 through AEB-R-12, which have been prepared by me or under my direction.

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

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

- In Section II, I provide a summary and overview of my Rebuttal Testimony.
- In Section III, I provide a summary of capital market conditions and their effect on the Cost of Equity for UNS Electric.
- In Section IV, I respond to Mr. Abinah's recommendations.
- In Section V, I respond to Mr. Mease's analyses and recommendations.
- In Section VI, I respond to Dr. Woolridge's analyses and recommendations.
- In Section VII, I respond to Mr. Chriss' recommendations.
- In Section VIII, I provide updated analyses regarding the Company's ROE and capital structure.
- Finally, in Section IX, I summarize my conclusions and recommendations.

II. SUMMARY AND OVERVIEW

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

A. The Opposing ROE witnesses have recommended ROE levels ranging from 8.35 percent in the case of Mr. Mease to 9.50 percent in the case of Mr. Abinah (see Table 1,

below). The FVROR recommendations of the Opposing ROE witnesses range from 5.24 percent to 5.64 percent.

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

Witness	Recommended ROE Range	Original Cost ROE Recommendation	FVROR Recommendation
Mr. Abinah	N/A	9.50%	5.64%
Mr. Mease	6.00%-8.95%	8.35%	5.26%
Dr. Woolridge	8.10%-9.00%	8.75%	5.24%
Mr. Chriss	N/A	Max of 9.50%	NA

Q. Please provide a brief overview of your response to Staff witness Abinah with respect to the ROE for UNS Electric.

A Staff recommends an ROE of 9.50 percent and a 0.50 percent Fair Value Increment for UNS Electric.[1] Staff's recommendations are based on the analysis that was prepared in two prior UNS Electric cases: Docket No. E-04204A-09-0206, and Docket No. E-04204-12-0504.[2] I understand that, as explained in the Rebuttal Testimony of Company witness Kentton Grant, UNS Electric would not oppose Staff's recommendation as long as the overall revenue increase and rate design approved provides UNS Electric a reasonable opportunity to earn that ROE. I also understand that the Company is not opposing Staff's recommendations for this specific case, while reserving the right to challenge such an approach in future rate cases for UNS Electric and its affiliates.

Mr. Abinah correctly recognizes that the Cost of Equity is prospective-looking even as he relies on the Staff witness analysis from two prior UNS Electric rate cases. Mr. Abinah's ROE recommendation is based on his view that a cost of capital analysis in

1 *See* Direct Testimony of Elijah Abinah, at 2.
2 *Ibid.*, at 3-4.

this docket would produce a similar, if not identical, range as was recommended by Staff in those cases of 8.5 percent to 10.5 percent. However, current capital market conditions fully support an ROE well in excess of 9.5 percent, and that 9.5 percent is, at best, the bottom of the range at this time. I disagree that the range identified by Staff in the two prior rate cases is appropriate, particularly the 8.5 percent bottom bracket. UNS Electric's willingness to accept the 9.5 percent ROE should not be interpreted to support the range previously recommended by Staff. My Rebuttal Testimony with respect to Staff's recommendation is intended to refute any assertions that the lower end of an appropriate ROE range is less than 9.5 percent, let alone 8.5 percent. Indeed, none of the ROE models in my Direct Testimony would support 8.5 percent as the low end of a reasonable range for ROE and would support an ROE above 9.5 percent.

As discussed in my Direct Testimony, capital market conditions today are different than the conditions that were present in Docket No. E-04204-12-0504.[3] In particular, credit spreads are wider today, suggesting higher risk aversion among investors. Government and corporate bond yields are projected to increase during the period in which rates are likely to be in effect for UNS Electric. Furthermore, market conditions are very different from when the Staff witness, Mr. Parcell, filed his analysis in Docket No. E-04204A-09-0206 in November 2009. At that time, the capital markets were just beginning to stabilize after the financial and credit crisis and the subsequent Great Recession. It is not reasonable to draw comparisons to that time period because financial markets were far from "normal", as evidenced by the unprecedented level of credit spreads and the extreme volatility in equity prices.

I have reviewed the analyses that were presented by Mr. Parcell in Docket Nos. E-04204-12-0504 and E-04204A-09-206, and I find that many aspects of those analyses are no

[3] Direct Testimony of Ann E. Bulkley, at 16-17.

longer relevant. For example, several of the proxy companies that were relied on in Mr. Parcell's analysis no longer exist as publicly traded companies due to merger activities, and many of the assumptions used in the ROE estimation models have changed significantly due to market conditions. Against the current economic and financial market backdrop, but for the Company's willingness to not oppose Staff's recommendation in this docket, it would certainly be reasonable to set the authorized ROE for UNS Electric above the current level of 9.50 percent.

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

A The methodology that Staff relies on to develop the FVROR is consistent with the methodology that was used in my Direct Testimony, assigning a return to the Fair Value Increment of one half the rate of inflation. As discussed above, the Company is prepared not to oppose Staff's recommendation. Absent this position by the Company, I believe that Staff's proposed cost rate for the Fair Value Increment is lower than what is reflective of current market conditions. Moreover, although this rate was approved by the Commission in Decision No. 74235, it was approved as one component of a settlement agreement that included many compromises between the parties in the case. In Decision No. 74235, the Commission found that the Settlement Agreement provided benefits to ratepayers, shareholders and the community "[b]ased on the totality of circumstances".[4] Therefore, the Commission did not specifically determine the methodology or cost rate to use in setting the FVROR in that case. Simply updating the inflation rate used in Staff's FVROR to the rate used in my analysis results in an increase in the FVROR of 24 basis points to 5.87 percent. Considering current economic and financial market conditions and the analysis presented in my direct

[4] Docket No. E-04204A-12-0504, Decision No. 74235, at 25.

testimony, but for the Company's willingness to not oppose Staff's recommendation in this docket, it would certainly be reasonable to set the FVROR above the current level of 0.50 percent.

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

A. As shown in Table 1 above, the range of ROE results presented by Mr. Mease is between 6.00 percent and 8.95 percent. Mr. Mease establishes this range using the low end of the range of his CAPM results and the mean result from his Constant Growth DCF model. In setting his range, Mr. Mease ignores the 9.63 percent ROE estimate that sets the high end of the range of his DCF analysis. Mr. Mease's recommended ROE of 8.35 percent is 115 basis points below the return that was authorized for UNS Electric in Docket No. E-04204-12-0504 and 95 to 205 basis points below the range of returns that has been authorized for integrated electric utilities in 2014 and 2015. Mr. Mease's recommended ROE is not a reasonable estimate of the Cost of Equity for UNS Electric. The specific areas of disagreement with Mr. Mease's ROE analyses on which he bases this recommendation are summarized below:

- Mr. Mease's recommendation to lower UNS Electric's currently authorized ROE by 115 basis points is inconsistent with the historical relationship between ROEs and interest rates. As discussed in my Direct Testimony, investors expect an increase in interest rates. As shown by the Bond Yield Risk Premium analysis, there is a positive relationship between interest rates and ROEs; therefore, suggesting a decrease in UNS Electric's authorized ROE in an increasing interest rate environment ignores that historical relationship.
- While Mr. Mease outlines the assumptions regarding dividend growth that are the foundation of the Constant Growth DCF model (i.e., dividends will grow at a

constant rate into perpetuity, and the dividend payout ratio will remain at a constant rate), he does not consider whether these assumptions are reasonable given recent and current market conditions. Mr. Mease's sole reliance on the Constant Growth DCF model does not take into consideration the effect of current market conditions. Other regulatory commissions have acknowledged that the results of the traditional ROE estimation models can be affected by market conditions. In particular, the FERC recently recognized that the DCF model results have been affected by "anomalous market conditions" and has relied on other ROE estimation models (such as the CAPM) for guidance on where within the range of results the ROE should fall.

- Mr. Mease's reliance on a historical market risk premium, calculated as an arithmetic or geometric mean, is inconsistent with the theory of a forward-looking ROE. Furthermore, the historical risk premium over the period from 2007-2009 decreased during the Great Recession, which is counterintuitive because risk aversion was higher among investors during this period (as shown by elevated market volatility and exaggerated credit spreads), suggesting that the market risk premium should also have been higher.

- Mr. Mease's sole reliance on the historical yields on U.S Treasury bonds in his CAPM analysis does not take into consideration the market's expectation that interest rates will be increasing over the period when the rates established in this proceeding are in effect.

- The results of Mr. Mease's CAPM analysis range from 6.00 percent to 7.19 percent. Mr. Mease states that these returns exceed a 4.60 percent yield by 107 to 228 basis points, suggesting that this range is an appropriate equity risk premium in current market conditions.[5] However, Mr. Mease's range is also 153 to 272

[5] *See* Direct Testimony of Robert B. Mease, at 14. The actual spread between Mr. Mease's results and a 4.60 percent yield is 140 to 259 basis points.

basis points below any authorized ROE for electric utilities in more than 30 years.[6] Therefore, it is not reasonable to afford any weight to the results of Mr. Mease's CAPM analysis.

- Applying reasonable adjustments to Mr. Mease's CAPM analysis results in a range of returns of 8.46 percent to 10.74 percent, with a mean of 9.93 percent. This represents an increase in the range of results of approximately 250 to 350 basis points.
- Mr. Mease's recommended FVROR is calculated by removing inflation from the Original Cost Rate of Return. Mr. Mease's calculation overstates the inflation in the FVRB by adjusting the FVROR by the full inflation rate. The FVRB is estimated using equal weightings of OCRB, which does not include inflation, and the estimated RCND, which is affected by inflation. Therefore, since only 50 percent of the FVRB is affected by inflation, it is not appropriate to adjust the entire FVROR by inflation. Rather, in order to properly remove inflation using Mr. Mease's approach, the inflation factor that is applied to the equity and debt cost rates should have been reduced by 50 percent, increasing Mr. Mease's FVROR by 67 basis points to 5.93 percent. Furthermore, adjusting the original cost ROE recommendation used in Mr. Mease's FVROR calculation to 9.36 percent increases the FVROR by 121 basis points to 6.47 percent.

Q. Please summarize your response to TASC witness Dr. Woolridge's ROE and equity ratio recommendations for UNS Electric.

A. Dr. Woolridge's analyses and ROE recommendation do not provide a reasonable estimate of UNS Electric's cost of capital. In particular, I disagree with Dr. Woolridge's recommendation for several reasons:

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[6] Source: SNL Energy, Inc. RRA rate case data from 1979 through 2015.

- Dr. Woolridge's 8.75 percent ROE recommendation is well below any recent ROE awards for vertically-integrated electric utilities and would not allow UNS Electric to compete for capital with other investments of comparable risk;
- Dr. Woolridge's Constant Growth DCF results of 8.70 percent to 9.00 percent are not reasonable because of the growth rate assumptions he relies on to specify the model. Dr. Woolridge's analysis includes historical growth rates for earnings, dividends and book value, projected internal or sustainable growth rates, and negative forecasted earnings growth rates. My Rebuttal Testimony discusses each of these assumptions and why it is more appropriate to rely on projected earnings growth rates in a DCF model.
- Dr. Woolridge's CAPM results of 8.10 percent to 8.30 percent are substantially lower than any authorized ROE for a vertically integrated electric utility in the U.S. in the last 25 years. Dr. Woolridge's analysis produces unreasonably low results because of the assumption he uses for the market risk premium. Dr. Woolridge has relied on a market risk premium of 5.50 percent, which does not reflect the inverse relationship between the equity risk premium and interest rates.
- Dr. Woolridge's proxy group of 29 electric utilities is not risk comparable to UNS Electric because he uses a revenue screen rather than an operating income screen; the proxy group includes companies that derive a significant percentage of their revenues from gas distribution operations, and companies that should be excluded for company-specific reasons.
- Dr. Woolridge has relied primarily on the results of his Constant Growth DCF analysis to support his ROE recommendation. He has given little or no weight to other, well-established models that I have used to estimate the Cost of Equity, such as the Multi-Stage DCF, a forward-looking CAPM, and the Bond Yield Plus Risk Premium analysis.

- Dr. Woolridge's 8.75 percent ROE recommendation fails to adequately consider capital market conditions, including the fact that credit spreads have been widening throughout 2015, and that interest rates on government and corporate bonds are expected to increase substantially over the next few years.
- Dr. Woolridge's proposal to impute a hypothetical capital structure consisting of 50 percent common equity and 50 percent long-term debt should be rejected. He has provided no reasonable basis for deviating from UNS Electric's actual test year capital structure which contains 52.83 percent common equity. The Company's proposed equity ratio is somewhat lower than the proxy group average common equity ratio of 53.72 percent.
- Dr. Woolridge does not propose a methodology to estimate the FVROR, agreeing to adopt the methodology relied on by Staff, substituting his recommendations for the OCRB ROE and capital structure. Applying those assumptions to the Staff methodology results in the lowest recommended FVROR of the Opposing ROE witnesses of 5.24 percent. As discussed previously, I disagree with Dr. Woolridge's capital structure and original cost rate base ROE estimates. Furthermore, as discussed in my response to the Staff, the use of a cost rate from 2009 and 2012 for the Fair Value Increment does not relate to the current market conditions and is not reasonable.

Q. Please summarize your response to Wal-Mart witness Mr. Chriss with respect to the ROE for UNS Electric.

A. Mr. Chriss does not recommend a specific ROE for UNS Electric. Rather, he suggests that the Commission should examine the Company's proposed 10.35 percent request in light of the customer impact of the resulting revenue requirement increases and recent

returns on equity for electric utilities approved by commissions nationwide.[7] Mr. Chriss testifies that the average authorized ROE for vertically-integrated electric utilities from 2012-2015 has been 9.98 percent, and that the trend in recent years has been toward declining allowed returns on equity. Mr. Chriss ultimately recommends that the Commission not allow an ROE higher than the current authorized level of 9.50 percent unless there is a showing that economic or capital market conditions are significantly different than at the time the current ROE was established.[8]

As discussed in my Direct and Rebuttal Testimony, economic and capital market conditions today are, in fact, different than in late 2013 when the Commission approved the settlement agreement, which included the current 9.50 percent ROE. As discussed in my response to Mr. Abinah, credit spreads are substantially wider today, suggesting higher risk aversion among investors, and both government and corporate bond yields are projected to increase during the period in which rates are likely to be in effect for UNS Electric, both of which suggest a Cost of Equity for UNS Electric above the current authorized level of 9.50 percent.

Q. Do you agree with Mr. Mease, Dr. Woolridge and Mr. Chriss that the Commission should consider ROE awards in other jurisdictions as a practical benchmark for assessing ROE recommendations?

A. Yes. I agree that ROE awards in other jurisdictions provide a useful benchmark to assist the Commission in assessing overall reasonableness and send an important signal to investors regarding whether there is regulatory support for financial integrity, dividends, and financial growth, and fair compensation for business and financial risk. The cost of capital represents an opportunity cost to investors. If higher returns are available for other investments of comparable risk, investors have the incentive to direct

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7 *See* Direct Testimony of Steve W. Chriss, at 4.
8 *Ibid.*, at 17.

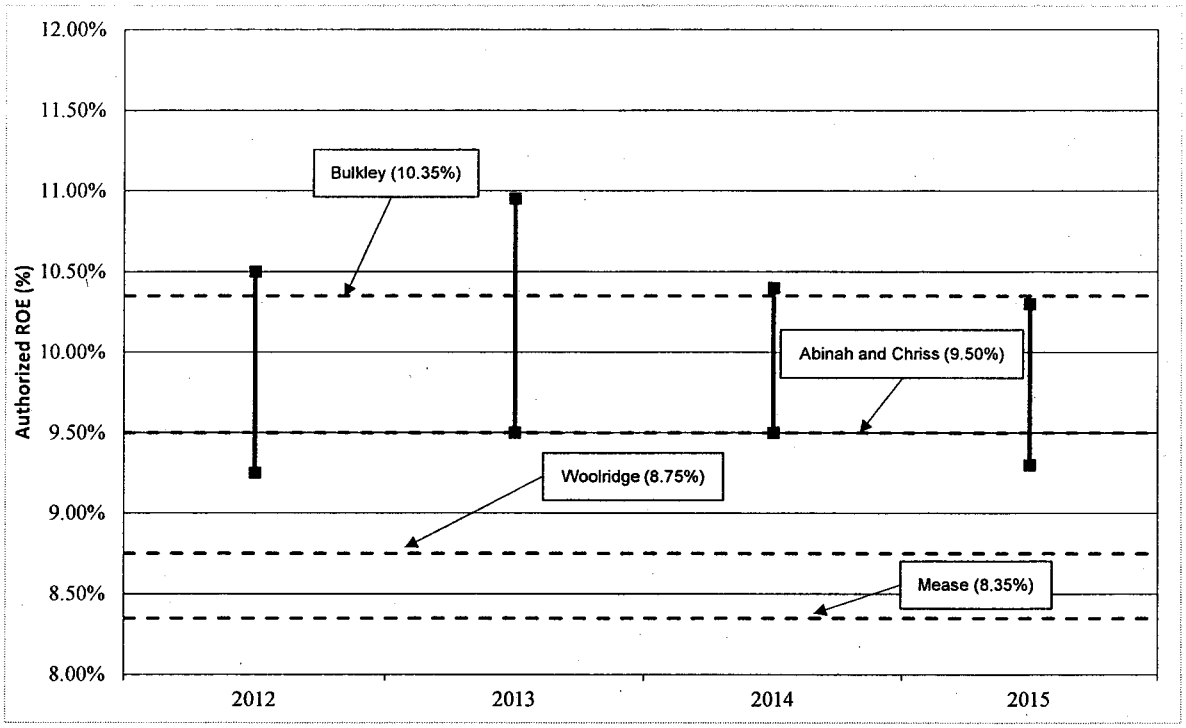
their capital to those investments. Thus, an ROE significantly below authorized ROEs in other jurisdictions can inhibit the Company's ability to attract capital for investment in Arizona.

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

A. Chart 1 provides the range of recently authorized ROEs. As shown on Chart 1, the ROE recommendations of Mr. Mease (8.35 percent) and Dr. Woolridge (8.75 percent) are well below the lowest authorized ROE for an integrated electric utility between January 1, 2012 and November 30, 2015. Both Messrs. Abinah and Chriss recommend an ROE not to exceed 9.50 percent, which is at the low end of the range of authorized returns for integrated electric utilities over this period, and well below the average ROE for integrated electric utilities of 9.98 percent that Mr. Chriss cites.

Chart 1: Authorized ROEs for Integrated Electric Utilities

January 1, 2012 – November 30, 2015[9]



Q. Have you updated your ROE analyses?

A. Yes. I have updated the analyses for the proxy group companies contained in my Direct Testimony to reflect data through November 30, 2015. My updated analysis excludes Southern Company and Duke Energy Corporation, which are both now parties to merger agreements and no longer meet my screening criteria on that basis. The results of my updated analyses are summarized in Table 2.

[9] Source: SNL Energy, Inc.

Table 2: Updated Analytical Results

	Mean Low	Mean	Mean High
Constant Growth DCF			
30-Day Average	8.41%	9.35%	10.32%
90-Day Average	8.50%	9.44%	10.42%
180-Day Average	8.52%	9.46%	10.43%
Multi-Stage DCF			
30-Day Average	9.29%	9.52%	9.78%
90-Day Average	9.39%	9.63%	9.89%
180-Day Average	9.40%	9.64%	9.91%
CAPM			
	Current Risk Free Rate (2.98%)	**2015-2017 Projected Risk Free Rate (3.37%)**	**2017-2021 Projected Risk Free Rate (4.80%)**
Bloomberg	9.67%	9.81%	10.34%
Value Line	11.21%	11.30%	11.61%
Bond Yield Plus Risk Premium			
	Low	**Mean**	**High**
Risk Premium	9.87%	10.04%	10.67%

Q. What is your conclusion regarding the appropriate Cost of Equity for the Company?

A. The ROE results presented in my Direct Testimony indicated a range of 10.00 percent to 10.60 percent from a combination of models and alternative input assumptions. As shown in Exhibits AEB-R-1 through AEB-R-6, I have updated my analyses through November 30, 2015, using the same models to estimate the Cost of Equity for UNS Electric. These updated results continue to support my initial ROE recommendation of 10.35 percent. ROEs at the levels proposed by Mr. Mease and Dr. Woolridge are not reasonable and would not meet the standards established in *Hope* and *Bluefield* for a fair return. Notwithstanding the Company's willingness to not oppose Staff's recommended 9.50 percent ROE, I believe that economic and financial market

conditions have changed since 2013 and that current conditions support an ROE higher than 9.50 percent. In particular, credit spreads are wider, market volatility has increased in 2015, and interest rates on government and corporate bonds are projected to rise over the next few years. For these reasons, capital costs are now higher than in 2013 and support my ROE recommendation of 10.35 percent for UNS Electric.

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

Q. Have the Opposing ROE witnesses considered the effect of economic and capital market conditions in establishing their respective ROE recommendations?

A. Messrs. Mease and Chriss, and Dr. Woolridge cite the current low interest rate environment as an important consideration in the Cost of Equity and as support for their low ROE recommendations. Staff does not discuss current economic and capital market conditions.. Dr. Woolridge and Mr. Chriss also cite the recent trend of declining average ROE awards for regulated electric utilities. The Opposing ROE witnesses' recommendations, however, are based on capital market conditions over the past few years, and do not adequately consider the changes that have occurred in recent months or the prospects for financial markets on a going-forward basis. In particular, Mr. Mease devotes a considerable portion of his testimony to discussing financial market conditions and utility stock performance in 2014, but does not consider market conditions in the last year or the expectations for changes in market conditions during the period when the rates that are decided in this case will be in effect. In my view, it is not reasonable to dismiss current and projected market conditions or to base the authorized ROE for UNS Electric in this proceeding on economic and financial market conditions from 2013 or 2014.

Rather, the ROE that is authorized in this proceeding is intended to provide a reasonable return to investors over the forward-looking period during which these rates will be in effect. For that reason, it is important to consider the prospects for financial markets during that period. As discussed in my Direct Testimony, extraordinary and persistent federal intervention in capital markets has artificially lowered government bond yields since the Great Recession of 2008-09, as the Federal Reserve has used monetary policy (both reductions in short-term interest rates and purchases of Treasury bonds and mortgage backed securities) to stimulate the U.S. economy.[10] This highly accommodative monetary policy has resulted in government bond yields that have been artificially suppressed by the Federal Reserve. However, as shown in Charts 2 and 3, market data suggest that investors perceive greater risk in the current market environment and expect rising interest rates. Therefore, it is important to consider the current and prospective market conditions and investor expectations for higher interest rates, all of which put upward pressure on utility capital costs going forward.

Q. Please discuss the recent change in monetary policy by the Federal Reserve.

A. At its December 2015 meeting, the FOMC voted to increase short-term interest rates by 25 basis points, and indicated its intention to gradually raise interest rates in coming months as economic conditions returned to normal after the financial and economic shocks that took place during the credit crisis and the ensuing Great Recession. The December 2015 FOMC decision provides confirmation that central bankers believe that economic conditions have improved sufficiently so as to justify a gradual increase in short-term rates. More importantly, yields on longer-term corporate and utility bonds, which are directly controlled by market forces rather than monetary policy, have been increasing throughout 2015. These market-based interest rates offer clear evidence that

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

investors are requiring higher rates of return to assume the risks associated with corporate debt. In short, capital costs are increasing and are expected to continue increasing as the FOMC gradually raises short-term interest rates.

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

A. As previously discussed, in mid-December 2015 the Federal Reserve announced the first increase in short-term interest rates since the financial market collapse in 2008. In its statement, the Federal Reserve indicated that further increases in short-term interest rates would be gradual as the economy strengthens further and inflation rises from undesirably low levels. The January 2016 issue of the Blue Chip Financial Forecasts ("Blue Chip") surveyed leading economists and market participants concerning their views about the likelihood of future increases in short-term interest rates by the Federal Reserve. Blue Chip reports that 73 percent of market participants surveyed expect the Federal Reserve to raise short-term interest rates again at the FOMC meeting in March with the expectation that there could be up to three short-term interest rate increases in 2016.[11]

According to Blue Chip, yields on 30-year Treasury bonds are forecasted to increase to 4.80 percent between 2017 and 2021.[12] Dr. Woolridge acknowledges the probability of tighter monetary policy, and uses a risk free rate of 4.00 percent in his CAPM analysis. However, Dr. Woolridge fails to recognize that current dividend yields of approximately 3.90 percent for utility shares will not be competitive with higher yields on government and corporate bonds. Consequently, the results of Dr. Woolridge's Constant Growth DCF analysis are understated because the current dividend yield

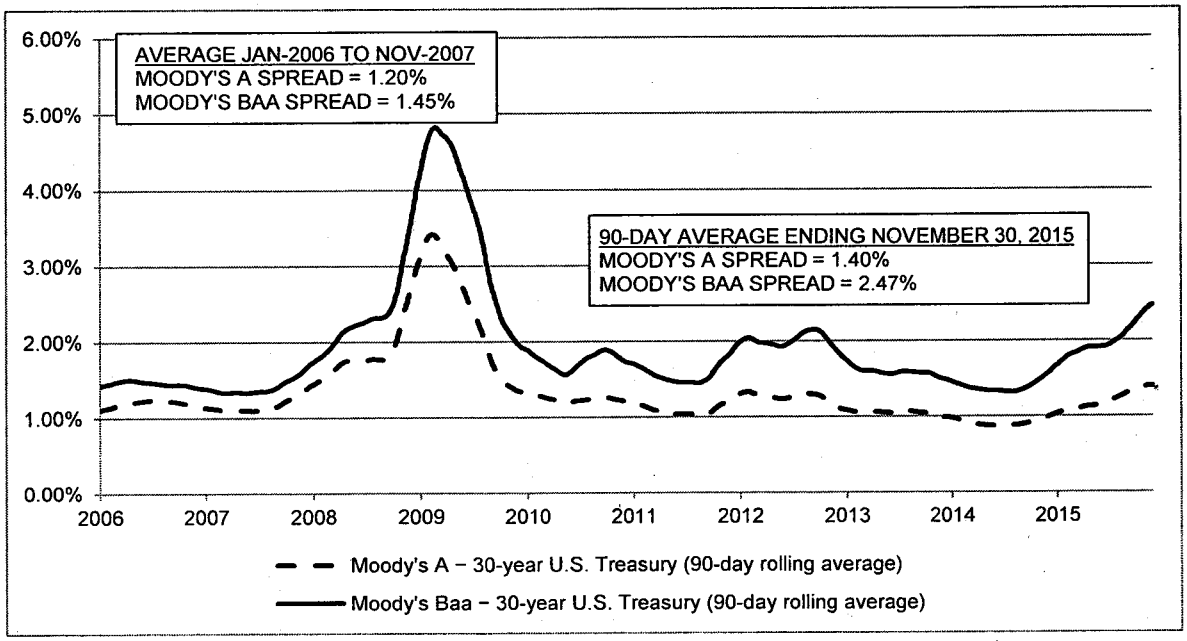
[11] Blue Chip Financial Forecasts, Volume 35, No. 1, January 1, 2016, at 14.
[12] Blue Chip Financial Forecasts, Volume 34, No. 6, June 1, 2015, at 14.

component does not adequately reflect the higher interest rate environment that he expects in his CAPM analysis.

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

A. The evidence of investors' increased risk sentiment is strong. Even as Treasury bond yields have remained relatively low in 2015, yields on corporate and utility bonds have increased steadily throughout the year. Consequently, as shown on Chart 2, credit spreads between government and utility bonds have increased to the highest level since the credit and financial crisis. In particular, the spread between Baa-rated utility debt and Treasury bonds is now more than 240 basis points, which is greater than the spread that occurred just prior to the Great Recession.

Chart 2: Credit Spreads for Moody's A- and Baa-rated Utility Bonds



Q. What do higher credit spreads indicate about the market?

A. Higher credit spreads are an indication that bond investors are becoming more concerned about future economic conditions and the ability of corporations to withstand any economic downturn that may occur. Recently, The Wall Street Journal reported on the trend toward higher credit spreads:

> The U.S. corporate-bond market is starting to flash caution signals about the broader economy. The difference in yield, called the "spread," between bonds from America's strongest companies and ultrasafe U.S. Treasury securities has been steadily increasing, a trend that in the past has foreshadowed economic problems. Wider spreads mean that investors want more yield relative to Treasurys to own bonds from U.S. companies. It can signal that investors are less confident about companies' business prospects and financial health, though other factors likely also are at play.
>
> Spreads in investment-grade corporate bonds – debt from companies rated triple-B minus or higher – are on track to increase for the second year in a row, according to Barclays data. That would be the first time since the financial crisis in 2007 and 2008 that spreads widened in two consecutive years.
>
> ***
>
> Investors and analysts say they are closely watching the action to determine whether trouble is brewing once again. Concerns are growing about companies' ability to pay back the massive debt load taken on in recent years, as ultralow interest rates spurred corporate finance chiefs to sell record amounts of bonds.[13]

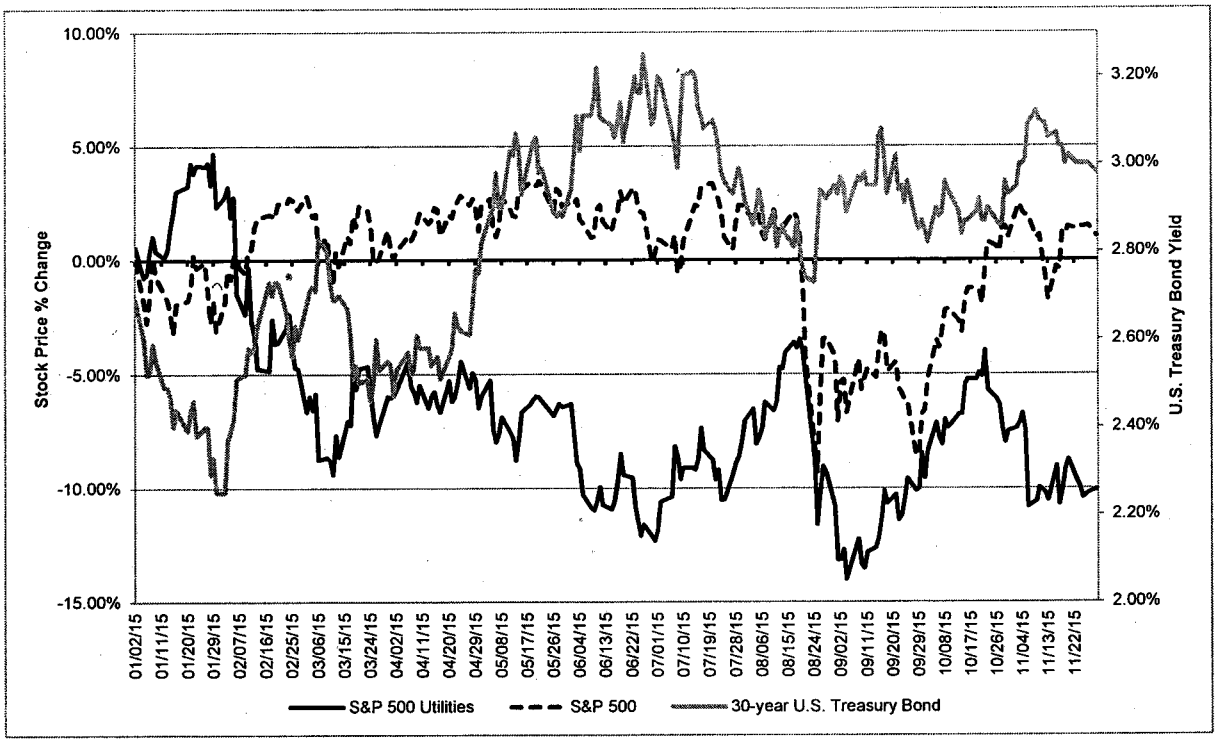
Q. How have equity markets reacted to widening credit spreads and the prospect for higher interest rates?

A. Equity markets have been declining in recent weeks and widening credit spreads signal possible economic distress ahead. As shown in Chart 3, utility stocks have underperformed the broader market since February 2015, as investors reacted to the gradual rise in Treasury bond yields. The broader market, as measured by the S&P 500, has been particularly volatile since mid-August, as equity investors contemplated the

[13] Mike Cherney, "U.S. Bonds Flash a Warning Sign," The Wall Street Journal, September 28, 2015, at C1.

prospect for higher interest rates and as global economic growth has slowed, especially in China.

Chart 3: 2015 Stock Performance Relative to U.S. Treasury Yields



Q. What is your conclusion regarding the effect of capital market conditions on the authorized ROE for UNS Electric?

A. Wider credit spreads between government and utility bond yields and increased market volatility are indications that investors are becoming more risk averse. Moreover, investors expect interest rates to increase as the Federal Reserve withdraws the extraordinary level of monetary stimulus that has been provided to the U.S. economy since the Great Recession. As interest rates rise, dividend yields on utility shares become less competitive with higher yields on government and corporate bonds. As a result of higher credit spreads, increased market volatility and rising interest rates, it is

reasonable to expect that the cost of capital for electric utilities such as UNS Electric is increasing, not decreasing.

IV. RESPONSE TO STAFF WITNESS ABINAH

Q. Please summarize Staff's ROE recommendation.

A. Staff recommends an ROE for UNS Electric of 9.50 percent, based on the Commission's December 31, 2013 decision approving the Settlement Agreement filed by the parties in Docket No. E-04204-A-12-0504. Staff cites the 2009 and 2012 rate cases filed by UNS Electric, in which Staff retained Mr. David Parcell to conduct cost of capital studies. Staff states that by approving the Settlement Agreement, the Commission found that the resulting rates were just, fair and reasonable.[14]

Q. What is your response to Staff's testimony and recommendation concerning the cost of capital?

A. I do not agree that it is "relevant, reasonable and consistent" to rely on the 2013 Settlement Agreement to set the authorized ROE for UNS Electric in this proceeding. One of the fundamental principles of the *Hope* and *Bluefield* decisions is that the cost of capital should be commensurate with returns available to other companies with comparable risk. Another fundamental principle of those decisions is that the cost of capital should be consistent with current economic and capital market conditions. As I have stated, the current economic and financial market conditions are not similar to those in 2013. Further, the 9.50 percent ROE recommendation is not consistent with recently authorized ROEs for vertically-integrated electric utilities in other jurisdictions.

[14] Direct Testimony of Elijah Abinah, at 5.

As shown in Chart 1, that recommendation is lower than almost all recently authorized ROEs.

Q. Do you agree with Staff that it is reasonable to conclude that the Cost of Equity for electric utilities today is in the range of 8.50 percent to 10.50 percent?

A. No, I do not. The basis for Staff's conclusion is that the Commission should rely on the Cost of Equity range presented in the testimony of Staff's witness, David C. Parcell, in the 2009 and 2012 UNS Electric rate cases. However, a reasonable cost of capital is highly dependent on the time period in which it is being established. Numerous changes have occurred since those 2009 and 2012 rate cases that make comparisons difficult, if not impossible. For example, many of the companies in the proxy groups used by Mr. Parcell have been involved in mergers and could not be used to estimate the Cost of Equity for UNS Electric today. Furthermore, economic and capital market conditions are very different in November 2015 than in June 2013 (when Mr. Parcell filed testimony in the 2012 rate case) or in November 2009 (when Mr. Parcell filed testimony in the 2009 rate case). In particular, monetary policy has evolved as the Federal Reserve introduced and ultimately discontinued its Quantitative Easing programs. Similarly, the interest rate outlook is very different because economic conditions have improved and unemployment has declined substantially, allowing the Federal Reserve to start the new cycle of monetary tightening. Likewise, credit spreads have increased significantly in 2015, as yields on utility bonds have risen more than 60 basis points since January, while yields on government bonds have been held down by highly accommodative monetary policy.[15] In addition, equity valuations have increased substantially since 2009, as investors have been willing to pay higher multiples for the earnings stream because the relative returns from bonds have been so depressed due to

[15] The Moody's A-rated utility bond index credit spread is 65 basis points. The spread for the Moody's Baa-rated utility bond index is greater than 100 basis points.

the low interest rate environment since the Great Recession. These higher equity valuations have been driven by monetary policy, which was intended to push investors out of lower-risk asset classes such as savings accounts and certificates of deposit, into higher-risk asset classes such as common equity. For all of these reasons, I do not agree that it is reasonable to rely on equity cost rates that were established under very different economic and capital market conditions, and using very different proxy groups of electric utility companies.

Q. Have you compared projected economic conditions today with those at the time when Mr. Parcell filed testimony in the 2009 and 2012 UNS Electric rate cases?

A. Yes, I have compared the current outlook for the U.S. economy to projected conditions in November 2009 and June 2013 when Mr. Parcell filed testimony in the two previous UNS Electric rate cases. As shown in Table 3, projected unemployment rates have declined substantially from 9.9 percent in November 2009 to 4.8 percent in November 2015. Similarly, projected growth in disposable personal income has increased from 1.4 percent in November 2009 to 2.7 percent in November 2015, as U.S. consumers are feeling more confident about prospects for employment, wage gains and economic growth. Forecasted real GDP growth has remained steady since 2009 as the economic recovery has been weaker than after most recessions, while the projected inflation rate is slightly lower than in November 2009, which allowed the Federal Reserve to maintain its "highly accommodative" monetary stance for longer than expected.

Table 3: Projected Key Economic Indicators[16]

	Nov. 2015 (for 2016)	June 2013 (data used in 2014 Settlement Agreement)	Nov. 2009 (data used in 2010)
Unemployment Rate	4.8%	7.1%	9.9%
Real GDP (annualized)	2.6%	2.6%	2.7%
Inflation (CPI)	1.8%	1.9%	2.0%
Disposable Personal Income	2.7%	2.6%	1.4%

Based on stronger conditions in employment markets, the Federal Reserve announced at the conclusion of the December 2015 FOMC meeting that it would increase short-term interest rates by 25 basis points, which marks the first increase in the Fed Funds rate in nine years.

Q. How do interest rates and credit spreads in December 2015 today compare with those at the time when Mr. Parcell filed testimony in the 2009 and 2012 UNS Electric rate cases?

A. As discussed in Section III, credit spreads have increased steadily throughout 2015 as yields on corporate and utility bonds have risen much more than yields on government bonds, which are still held artificially low by monetary policy. As shown in Table 4, 90-day rolling average credit spreads between 30-year Treasury bonds and Moody's Baa and A-rated utility bonds are higher now than in June 2013. It is not reasonable to compare the current market conditions to those in November 2009 because financial and credit markets in 2009 were still impacted by the financial crisis, and credit spreads were exaggerated.

[16] Sources: Blue Chip Economic Indicators, Volume 40, No. 11, November 10, 2015, at 4, Blue Chip Economic Indicators, Volume 38, No. 6, June 10, 2013, at 4, and Blue Chip Economic Indicators, Volume 34, No. 11, November 10, 2009, at 4.

Table 4: Interest Rates and Credit Spreads[17]

	11/30/2015	6/28/2013	11/6/2009
90-day average yield U.S. Treasury bonds	2.93%	3.14%	4.29%
90-day average yield Moody's Baa-rated bond	5.40%	4.73%	6.37%
Spread between 30-year U.S. Treasury and Moody's Baa-rated utility bond index	2.47%	1.58%	2.08%
Spread between 30-year U.S. Treasury and Moody's A-rated utility bond index	1.40%	1.07%	1.40%
Spread between Moody's Baa and A-rated bond index	1.07%	0.51%	0.68%

Rising credit spreads are an indication of increased investor risk aversion. Equity markets have been more volatile in 2015, and stock prices have declined in 2015 for dividend paying stocks such as electric utilities which are more sensitive to higher interest rates. As such, rising credit spreads are another indication that capital costs are higher today than at the time Mr. Parcell filed his testimony in the 2012 UNS Electric rate case.

Q. Which proxy group companies that were used by Mr. Parcell in his DCF, CAPM, and Comparable Earnings analyses in the 2009 and 2012 rate cases could not be used today to estimate the Cost of Equity for UNS Electric?

A. Consistent with most analysts, Mr. Parcell relies on a merger screening criteria, excluding companies from his analysis that are involved in transformative transactions. Several companies that were included in Mr. Parcell's 2009 and 2012 analyses of the Cost of Equity could not be used currently because they have either been acquired or are involved in mergers/acquisitions. Based on his November 2009 testimony, three of

[17] Source: Bloomberg Professional.

seven companies would be excluded from his proxy group on this basis: Hawaiian Electric; Pepco Holdings; and TECO Energy. Based on Mr. Parcell's June 2013 testimony, four of the eight companies would be excluded from his proxy group: Cleco Corp; Hawaiian Electric; Pepco Holdings; and UIL Holdings. In both cases, that would leave only four companies in the Parcell proxy group, which is generally not considered a sufficient sample size for an ROE analysis.

Q. Is Staff's ROE recommendation of 9.50 percent consistent with returns for integrated electric utilities in other jurisdictions across the U.S.?

A. As shown in Chart 1, Staff's ROE recommendation of 9.50 percent is on the lower end of recent ROE awards for integrated electric utilities. Forward-looking economic and capital market conditions as well as UNS Electric's additional business risks support an authorized ROE *above* the proxy group average and higher than 9.50 percent. As discussed in my Direct Testimony, UNS Electric is smaller than the proxy group companies, has an elevated level of capital expenditures compared to the companies in the proxy group, and has above average regulatory risk in Arizona.[18]

Q. What is your conclusion regarding Staff's ROE recommendation of 9.50 percent?

A. While UNS Electric would not oppose Staff's ROE recommendation as long as the overall revenue increase and rate design approved provides UNS Electric a reasonable opportunity to earn that ROE, the results of the ROE estimation models and the risk factors discussed in my Direct and Rebuttal Testimony demonstrate that the appropriate ROE today is significantly higher than the 9.50 percent that was approved in the Settlement Agreement in the Company's last rate case. As I have demonstrated, conditions in capital markets suggest that investors are more risk averse now than in

[18] Direct Testimony of Ann E. Bulkley, at 41-49.

2013, as shown by higher yields on corporate and utility bonds, wider credit spreads between government and corporate debt, declining valuations for utility shares, and more volatility in the broader equity markets. Furthermore, ROE awards for integrated electric utilities have generally been above the 9.50 percent level in 2014 and 2015. Taking into consideration UNS Electric's above average business risk, I believe that an authorized ROE above recent returns for other integrated electric utilities is justified.

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

A. Staff summarizes the FVROR that was adopted by the Commission in the UNS Electric cases since 2009, noting that the Commission applied a cost rate of 2.10 percent to the Fair Value Increment in Decision No. 71914 and 0.50 percent in Decision No. 74235. Based on this review, Staff recommends that the Commission approve a cost rate of 0.50 percent for the Fair Value Increment in this proceeding.[19]

Q. Do you agree with Staff's recommendation?

A. The methodology that was used in Decision Nos. 71914 and 74235 and are relied on currently by Mr. Abinah is consistent with the methodology used in my Direct Testimony, assigning a return to the Fair Value Increment. However, I believe that current economic and market conditions would support a cost rate that is higher than Staff proposes to apply to the Fair Value Increment. Similar to the ROE recommendation, Staff's proposed cost rate on the Fair Value Increment is based on the recommendation of Mr. Parcell in Docket No. E-04204-A-12-0504, which relied on data from 2012.

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[19] Direct Testimony of Elijah Abinah, at 11.

While the Commission approved a 0.50 percent cost rate for the Fair Value Increment in Decision No. 74235, that rate was approved as part of a Settlement Agreement. In the conclusions in that decision, the Commission specifically noted that the Settlement Agreement provided benefits to ratepayers, shareholders and the community and represented a fair and balanced resolution of all issues "[b]ased on the totality of circumstances". Therefore, the Commission did not specifically determine that this cost rate was the appropriate rate to be used for the Fair Value Increment.

Even if the Commission had specifically approved a 0.50 percent rate in Decision No. 74235, that cost rate was based on market conditions at the time of that proceeding, which relied on data from 2012. As discussed in my response to Staff's ROE recommendation, market conditions have changed significantly since December 2013. Therefore, even though UNS Electric would not oppose Staff's 0.50 percent rate recommendation as long as the overall revenue increase and rate design approved provides UNS Electric a reasonable opportunity to earn its authorized ROE, the data presented in my Direct Testimony demonstrates that the inflation rate that could be applied to the fair value increment rate is higher than the 0.50 percent in the Settlement Agreement approved in the Company's last rate case.

V. RESPONSE TO RUCO WITNESS MEASE

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

A. Based on his analyses, Mr. Mease develops a range of ROE results from 6.00 percent to 8.95 percent, and recommends an ROE for UNS Electric of 8.35 percent.[20] The mean result of Mr. Mease's Constant Growth DCF analysis forms the upper boundary of his range of results, while the lower boundary is based on the lowest result from his CAPM

[20] Direct Testimony of Robert B. Mease, at 14.

analysis using a geometric mean market risk premium. Mr. Mease ignores the high end of the range of results of 9.63 percent established using his DCF analysis. Mr. Mease indicates that his point estimate of 8.35 percent is slightly above the midpoint of his arithmetic mean CAPM result of 7.19 percent and his Constant Growth DCF result of 8.95 percent. Mr. Mease testifies that his ROE recommendation is consistent with the current low interest rate environment[21], and that electric utility shares enjoyed strong returns in 2014 as compared to the broader market.[22] Mr. Mease supports the Company's proposed capital structure of 52.83 percent common equity and 47.17 percent long-term debt. Mr. Mease calculates the weighted average cost of capital of 6.86 percent, then deducts 0.25 percent as an inflation adjustment. Further, Mr. Mease recommends a FVROR for UNS Electric of 5.26 percent, which he derives by subtracting an inflation rate of 1.35 percent from his inflation adjusted weighted average cost of capital of 6.61 percent.

Q. Is Mr. Mease's ROE recommendation of 8.35 percent fair and reasonable for UNS Electric?

A. No, Mr. Mease's ROE recommendation of 8.35 percent is 115 basis points below UNS Electric's currently authorized ROE and is substantially lower than returns available from other comparable-risk investments. Mr. Mease provides no analysis that demonstrates that the Cost of Equity has declined since UNS Electric's last rate proceeding to justify such a significant reduction in the Company's Cost of Equity. Mr. Mease's discussion of economic and capital conditions is largely outdated and does not reflect the reality of higher credit spreads, or prospects for higher interest rates, or the volatility that has characterized the broader equity market in recent months. As a result, Mr. Mease's recommendation does not reflect the current and prospective market

[21] *Ibid.*, at 26.
[22] *Ibid.*, at 21.

conditions that UNS Electric will experience when the return that is decided in this case will be in effect. Finally, Mr. Mease has failed to take into consideration additional business and regulatory risks which differentiate UNS Electric from the proxy group companies, such as UNS Electric's significant capital expenditure requirements, the Company's small size, and the uncertain regulatory environment in Arizona.

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

A. I disagree with the following aspects of Mr. Mease's analyses: (1) his sole reliance on a Constant Growth DCF model and his failure to consider a Multi-Stage DCF analysis; (2) his use of projected dividend growth rates in the Constant Growth DCF model; (3) his failure to consider the full range of results in the DCF analysis; (4) his application of the CAPM and the reasonableness of his CAPM results; (5) his failure to take into consideration the higher business and regulatory risks to which UNS Electric is exposed relative to the proxy group companies; and (6) his FVROR recommendation and the method used to derive that recommendation.

A. Application of the Constant Growth DCF Model

Q. What are your concerns with Mr. Mease's sole reliance on the Constant Growth form of the DCF model?

A. Mr. Mease's analysis does not consider the possibility that growth rates may change over time, something that is important to consider, especially as macroeconomic conditions are recovering very slowly from a significant market shock. Mr. Mease identifies specifically that the DCF model he relies on assumes that: 1) dividends will grow at a constant rate into perpetuity, and 2) the dividend payout ratio will remain at a

constant rate.[23] Mr. Mease notes that both assumptions are based on the underlying assumption that earnings, dividends, book value and share growth all increase at the same rate into infinity. Based on recent market conditions, it is reasonable to expect that growth rates will change over time and to reflect that in the analysis using a Multi-Stage model.

Q. Do you agree with the proxy group that Mr. Mease relies on for his DCF analysis?

A. While the proxy group companies are generally similar to the group that I relied on in my Direct Testimony, since that testimony was filed, Southern Company has entered into a merger agreement. Therefore, Southern Company would no longer meet my screening criteria and would be excluded from the proxy group during the analytical period that Mr. Mease relied on. As shown on Exhibit AEB-R-7, removing Southern Company from Mr. Mease's analysis would increase the mean results of his DCF analysis to 9.00 percent and the high end of the range to 9.71 percent.

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

A. Mr. Mease states that dividend growth can be measured using the product of a company's retention ratio and its return on book equity.[24] This is the sustainable growth rate commonly expressed as the "b" x "r" growth rate. However, in Exhibit RBM-5, Mr. Mease's analysis relies on both projected dividend growth rates, as reported by Value Line, and analysts' projected earnings growth rates as, reported by Yahoo! Finance, not on sustainable growth, as his testimony implies.

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[23] Direct Testimony of Robert B. Mease, at 8.
[24] Ibid, at 9.

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

A. Not entirely. Mr. Mease relies on an average of projected dividend per share growth and earnings per share growth rates to estimate the growth rate in the DCF model. Estimates of earnings growth are more indicative of long-term investor expectations than are dividend or book value growth estimates because earnings growth is least influenced by capital allocation decisions that companies may make in response to near-term changes in the business environment. Furthermore, earnings are the fundamental driver of a company's ability to pay dividends. As noted by Brigham and Houston:

> Growth in dividends occurs primarily as a result of growth in earnings per share (EPS). Earnings growth, in turn, results from a number of factors, including (1) inflation, (2) the amount of earnings the company retains and invests, and (3) the rate of return the company earns on its equity (ROE).[25]

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

Q. How would the results of Mr. Mease's DCF analysis change if he relied only on projected earnings per share growth rates?

A. As shown on Exhibit AEB-R-7, the results of Mr. Mease's DCF analysis excluding Southern Company would increase by 35 basis points to 9.35 percent.

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

Q. Are there other assumptions in Mr. Mease's DCF analysis that you disagree with?

A. Yes. Mr. Mease's growth rates and the pricing data are not based on the same time periods. Mr. Mease relies on pricing data for the period from July 1, 2015 through September 30, 2015 from Yahoo! Finance, but uses earnings growth rates as of October 29, 2015. The more common approach to specifying the DCF model is to use growth rates and pricing data for the same valuation period.

Q. What is the appropriate correction to make for this error?

A. It is necessary to align the growth rates and the prices to the same analytical period. As shown in Exhibit AEB-R-7, adjusting Mr. Mease's analytical period to September 30, 2015, to be consistent with the pricing data that he has relied on increases his DCF result using EPS growth rates and excluding Southern Company to 9.36 percent.

Q. Please summarize the effects of the changes that you made to Mr. Mease's DCF results.

A. As shown in Table 5 below, by making corrections and appropriate changes to Mr. Mease's DCF analysis, the mean ROE range of results increases by 28 to 56 basis points and overlaps my recommended range of 10.00 to 10.60 percent.

Table 5: Summary of Adjustments to Mease DCF

	ROE Range
Filed	8.26%-9.63%
Excl. SO	8.28%-9.71%
Excl. SO, & Using EPS	8.44%-10.27%
Excl. SO, Using EPS & Using Sept. Data	8.54%-10.19%

Q. Do you agree with the range of results Mr. Mease relies on from his DCF analysis?

A. No, I do not. Mr. Mease's DCF analysis estimates the ROE that results from using a low, mean, and high growth rate. As shown in Exhibit RBM-5, the range of results from that analysis is 8.26 percent to 9.63 percent, with a mean result of 8.95 percent. Mr. Mease's recommended ROE for UNS Electric of 8.35 percent is 60 basis points below the mean result of his DCF analysis and only nine basis points higher than his low DCF result. Mr. Mease provides no evidence to demonstrate why he believes that the business risk that UNS Electric faces is lower than the average risk of the proxy companies that he relies on. Furthermore, Mr. Mease disregards the high end of the range of his DCF results without providing any rationale for excluding these results.

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

A. Yes, I have. While the commission in that case did rely on the DCF model, there are other important factors to be noted from this decision. First, the commission indicated that while it has a preference for the DCF model, it does not preclude parties from filing other approaches and most importantly, the commission considered the entire record, "which may include actions taken by other commissions and recent changes in the law."[26] Furthermore, the commission set the upper bound of the ROE at the high end of the range of the Constant Growth DCF results, calculated based on the high earnings per share growth rates; similar to the calculation that Mr. Mease performed that resulted in an ROE of 9.63 percent which was ignored in establishing his range. Finally, it is important to note that the ROE that was established by that commission in 2014 for Potomac Electric Power (a lower-risk transmission and distribution only utility) was 9.50 percent, or 115 basis points higher than the ROE recommended by Mr. Mease.

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

1

2 **B. Application of Capital Asset Pricing Model**

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

4 A. Mr. Mease's CAPM analysis relies on a historical market risk premium ("MRP"),
5 calculated using both the geometric and arithmetic averages, and the three month
6 historical average yield on 30-year Treasury bonds of 3.01 percent as the risk free rate.
7 That analysis produces an ROE estimate for UNS Electric of 6.00 percent using a
8 geometric mean MRP and 7.19 percent using an arithmetic mean MRP.[27] Mr. Mease
9 relies on average Value Line Beta coefficients for the proxy group of 0.75, and a MRP
10 of either 4.0 percent (geometric mean) or 5.60 percent (arithmetic mean).[28] Despite the
11 fact that Mr. Mease's CAPM analysis produces an ROE estimate as much as 350 basis
12 points below the currently authorized ROE for UNS Electric, Mr. Mease does not
13 question the reasonableness of his CAPM results, establishing the low end of his range
14 for a cost of common equity for UNS Electric at 6.00 percent, which is the low end of
15 the results of his CAPM analysis.[29]

16

17 **Q. Please comment on the reasonableness of Mr. Mease's CAPM results.**

18 A. Mr. Mease's CAPM results of 6.00 percent and 7.19 percent are entirely inconsistent
19 with the returns required by equity investors for companies with commensurate risk. As
20 noted previously, these results are 231 to 350 basis points below UNS Electric's
21 currently authorized ROE and suggest an equity risk premium of only 134 to 253 basis
22 points above the Company's embedded debt cost of 4.66 percent. The high end of this
23 range is approximately half of the equity risk premium implied by Staff's

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27 Direct Testimony of Robert B. Mease, at 14.
28 Exhibit RBM-6.
29 Direct Testimony of Robert B. Mease, at 14.

recommendation, and a 6.00 percent ROE suggests an equity risk premium that is slightly more than 25 percent of the equity risk premium proposed by Staff's recommended ROE. Furthermore, neither of Mr. Mease's average CAPM results has ever been observed as an authorized ROE for any electric utility in at least the past 25 years. Mr. Mease's CAPM results are as low as 5.21 percent (geometric mean) and 6.09 percent (arithmetic mean) for an individual company (Southern Company).

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

A. No, I do not. As Mr. Mease notes, the Commission has stated that "the consideration of both historical and projected data is appropriate in evaluating the Cost of Equity".[30] Therefore, the use of only the three month historical average yield of 3.01 percent as the risk free rate in the CAPM analysis is not reasonable, especially when considering investors' expectation for rising interest rates during the period when this return will be in effect. Furthermore, Mr. Mease fails to take into consideration the inverse relationship between interest rates and the MRP. That is, if current interest rates are approximately 300 basis points below historical levels, it is not appropriate to use the three month average historical yield on 30-year Treasury securities as the risk free rate in conjunction with the historical MRP from Morningstar. Furthermore, Mr. Mease submitted the only independent CAPM analysis that does not consider the effect of rising interest rates on the Cost of Equity. Projected yields on 30-year Treasury securities indicate that investors are expecting substantially higher interest rates and higher inflation over the next five years.

[30] Direct Testimony of Robert B. Mease at 16. See also Decision No. 75268.

Q. Do you agree with the method Mr. Mease has used to derive his MRPs of 4.00 percent and 5.60 percent?

A. No. I disagree with Mr. Mease's MRPs for three reasons. First, Mr. Mease has subtracted the total return on government bonds rather than the income only return on those bonds from the total return on large company stocks. Second, Mr. Mease relies on both the geometric and arithmetic mean MRP. Third, as noted above, Mr. Mease has failed to consider the inverse relationship between interest rates and the MRP, which suggests that it is not appropriate to use a current risk free rate in conjunction with a historical MRP when the current risk free rate is substantially lower than the government bond yield that was used to derive the historical MRP. For all of these reasons, Mr. Mease's MRP is under-stated and does not reflect investors' expectations for future equity returns.

Q. How would you correct the MRP used in Mr. Mease's analysis?

A. It is important to take into consideration the relationship between interest rates and the MRP. Therefore, if Mr. Mease is relying on the three month average historical yield on Treasuries of 3.01 percent as the estimate of the risk-free rate, that same yield should also be used in the estimation of the MRP. As shown in Schedule RBM-6, Mr. Mease's calculation of the MRP is based on a risk-free rate of 6.40 percent and relies on a three-month historical risk-free rate of 3.01 percent in the CAPM. The estimation of the MRP should reflect the current MRP and therefore should rely on the estimate of the current risk-free rate. Correcting the MRP to rely on the current risk-free rate of 3.01 percent increases the MRP to 8.99 percent from 5.60 percent.

Q. Why is it not appropriate to use the total return on government bonds to derive the MRP?

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

> Another point to keep in mind when calculating the equity risk premium is that the income return on the appropriate-horizon Treasury security, rather than the total return, is used in the calculation. The total return is comprised of three return components: the income return, the capital appreciation return, and the reinvestment return...The income return is thus used in the estimation of the equity risk premium because it represents the truly riskless portion of the return.[31]

By subtracting the total return on government bonds from the total return on large company stocks, Mr. Mease has understated the historical MRP by approximately 140 basis points (using the arithmetic mean).[32] Based on Mr. Mease's average Beta coefficient of 0.75, the effect on his mean CAPM estimate is approximately 35 basis points. Even that correction, however, renders results that are far too low to be reasonable estimates of UNS Electric's Cost of Equity.

Q. What is the difference between the geometric and arithmetic mean for calculating the MRP?

A. Although I do not endorse the use of a historical MRP, the arithmetic risk premium best approximates the uncertainty associated with returns from year to year. The arithmetic mean is the simple average of single period rates of return, while the geometric mean is the compound rate that equates a beginning value to its ending value. The important distinction between the two methods is that the arithmetic mean assumes that each

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

[32] *Ibid.*, at 23.

periodic return is an independent observation and, therefore, incorporates uncertainty into the calculation of the long-term average. By contrast, the geometric mean does not incorporate the same degree of uncertainty because it assumes that returns remain constant from year to year. In his review of literature on the topic, Cooper noted the following rationale for using the arithmetic mean:

> Note that the arithmetic mean, not the geometric mean is the relevant value for this purpose. The quantity desired is the rate of return that investors expect over the next year for the random annual rate of return on the market. The arithmetic mean, or simple average, is the unbiased measure of the expected value of repeated observations of a random variable, not the geometric mean....[The] geometric mean underestimates the expected annual rate of return.[33]

Q. How can the projected MRP be estimated?

A. As discussed in my Direct Testimony, a reasonable method to estimate the forward-looking MRP is to subtract the projected 30-year Treasury bond yield from the expected return on the S&P 500 Index.[34] Based on an estimated weighted-index dividend yield of 2.13 percent and a weighted-index long-term growth rate of 11.26 percent, the required S&P 500 market return is approximately 13.51 percent. The implied MRP over the projected 30-year Treasury yield is 8.71 percent, or 311 to 471 basis points higher than Mr. Mease's estimates of 4.00 percent and 5.60 percent.

Q. Have you estimated the change in the CAPM range of returns resulting from these proposed adjustments?

A. Yes. Exhibit AEB-R-8 adjusts Mr. Mease's CAPM analysis for the following changes: 1) updated the historical arithmetic mean market return; 2) adjusted the risk free rate used in the calculation of the MRP to be consistent with the current risk free rate; and 3)

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

34 Direct Testimony of Ann E. Bulkley, at 36-37.

adjusted proxy group to exclude Southern Company. As shown in that Exhibit, the range of returns increases to 8.46 percent to 10.74 percent, with a mean ROE estimate of 9.93 percent.

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

A. Mr. Mease's inputs to the CAPM analysis are based on historical data rather than forward-looking investor expectations. Under the current interest rate environment, the CAPM does not produce reliable results without making adjustments to certain inputs and assumptions. Consequently, Mr. Mease's CAPM analysis provides no meaningful insight into the Cost of Equity for UNS Electric and should not be used to establish the reasonable range of ROE estimates in this proceeding.

C. Fair Value Rate of Return

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

A. Mr. Mease recommends a FVROR of 5.26 percent for UNS Electric, which is derived by subtracting an inflation rate of 1.35 percent from his overall cost of capital of 6.61 percent.[35] Mr. Mease's inflation rate is based on a seven-year historical average difference between the yield on Treasury Inflation Protected Securities ("TIPS") and comparable Treasury securities with similar liquidity and duration.

[35] Direct Testimony of Robert B. Mease, at 5. Also, see Schedule RBM- 1, page 1.

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

A. No, I do not. First, I disagree with the application of the entire inflation factor to the OCROR; in addition, I disagree with the specific estimate of inflation that was used in Mr. Mease's analysis.

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

A. Based on the methodology that has been used to estimate the FVRB, it is not reasonable to reduce the entire OCROR by the inflation factor. The FVRB is estimated by equally weighing the Original Cost Rate Base ("OCRB") and the Replacement Cost New Depreciated ("RCND") estimate of the value of the rate base. Only the RCND has an inflation component. Therefore, the application of the inflation rate to the entire FVRB incorrectly reduces the original cost portion of the rate base when that cost component does not include inflation. Therefore, if the inflation factor is to be applied to the OCROR, it should be reduced by 50 percent to reflect the fact that 50 percent of the FVRB has no inflation component.

Q. Does Mr. Mease recognize that the FVRB is based on OCRB and RCND?

A. Yes, Mr. Mease recognizes that it is the RCND that includes inflation and suggests that the difference in the value of the OCRB and the FVRB is "due entirely to inflation."[36]

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

A. The calculation proposed in my Direct Testimony is consistent with the methodology proposed by Staff. This approach assigns a separate return on the Fair Value Increment,

[36] RUCO response to UNS 3.1.

which is the difference between the OCRB and the FVRB. As shown in Exhibit AEB-R-11, I calculate the FVROR by applying the equity cost rate of 10.35 percent to the equity component of the OCRB, and the debt cost rate to the debt component of the OCRB without adjustment. The Fair Value Increment is then assigned a cost rate equal to one half of the inflation rate.

Q. Why do you disagree with the inflation rate relied on by Mr. Mease?

A. The inflation expectations over the historical period Mr. Mease relied on range from 0.48 percent in 2015 to 2.23 percent in 2011.[37] Since 2011, the inflation rate that is projected using Mr. Mease's methodology has been declining. Therefore, relying on a long-term historical average over this period significantly overstates the expected inflation using his methodology. Furthermore, as discussed in the Rebuttal Testimony of Mr. Grant, very minor changes in expected inflation produce significant changes in the FVROR and overall revenue requirement. Significant variability in the revenue requirement resulting from this methodology exposes UNS Electric to much greater risk than the proxy companies.

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

A. As discussed in the testimony of Company witness Grant, the application of Mr. Mease's 1.35 percent inflation factor to the Company's proposed WACC would result in a FVROR of 6.32 percent, which is slightly higher than the result of the methodology developed in my Direct Testimony.

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[37] Schedule RBM-4.

Q. Do you agree then with Mr. Mease's recommended FVROR?

A. No, I do not. Mr. Mease applies the inflation factor of 1.35 percent to his recommended OCROR, which includes an equity rate of 8.35 percent. For the reasons discussed in my response to Mr. Mease's estimated ROE, I disagree with that proposed equity rate. Mr. Mease's recommended FVROR of 5.26 percent, which is developed from his equity cost rate and FVROR methodology, is significantly below the returns for other companies of similar risk and does not reflect the cost of capital for UNS Electric.

Q. What changes would you propose to Mr. Mease's recommended FVROR?

A. As discussed above, it is appropriate to adjust the inflation factor by 50 percent to reflect the fact that the FVRB is derived only 50 percent from the RCND. In addition, it would be appropriate to adjust the equity cost rate to a more reasonable estimate of the cost of equity.

Q. What is the resulting FVROR with your proposed changes to Mr. Mease's analysis?

A. Exhibit AEB-R-9 provides the result of those proposed changes. Relying on the adjusted DCF value shown in Table 5, and applying 50 percent of Mr. Mease's inflation factor results in a FVROR of 6.47 percent.[38]

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

A. I continue to support the methodology used in my Direct Testimony to establish the FVROR. That approach suggests a return on the Fair Value Increment between the

[38] The use of a 9.35 percent ROE in this calculation does not suggest that this is the appropriate cost of equity for UNS Electric. Rather, this analysis demonstrates that using a return that is more consistent with Staff's proposal and a reasonable inflation factor would result in a FVROR that is similar to the FVROR proposed by the Company.

projected risk free rate and the ROE. The methodology that I have employed is consistent with the approach proposed by Staff, though the inflation factors differ. Specifically, I conclude that the minimum ROR that should be applied to the Fair Value "Increment" of rate base is the real risk free rate, which I estimate to be 3.01 percent.[39] The Company continues to advocate the use of 50.00 percent of the risk free rate in the estimate of the FVROR calculation to moderate the effect of the rate increase on customers. Applying 50 percent of the risk free rate to the Fair Value Increment results in a FVROR of 6.22 percent, which I believe is conservative.

VI. RESPONSE TO TASC WITNESS DR. WOOLRIDGE

Q. Please provide a summary of Dr. Woolridge's testimony and recommendations.

A. Dr. Woolridge develops a range of results from 8.10 percent to 9.00 percent, and recommends an ROE for UNS Electric of 8.75 percent. Dr. Woolridge arrives at his recommendation by relying primarily on the results of his Constant Growth DCF analysis. He presents results for his proxy group of electric utilities, as well as my original proxy group excluding Southern Company. Dr. Woolridge's DCF results of 8.70 percent to 9.00 percent are based on his use of historical earnings growth rates, projected dividend and book value growth rates, and retention growth rates, as well as projected earnings growth rates from Value Line, First Call, Zack's and Reuters. In addition, Dr. Woolridge presents a CAPM analysis, which produces a Cost of Equity estimate between 8.10 percent and 8.30 percent depending on the proxy group. Dr. Woolridge also recommends a hypothetical capital structure comprised of 50 percent common equity and 50 percent long-term debt, rather than UNS Electric's actual test year capital structure of 52.83 percent equity and 47.17 percent long-term debt.

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[39] *See* Direct Testimony Exhibit AEB-R-11.

Q. Is Dr. Woolridge's 8.75 percent ROE recommendation fair and reasonable for UNS Electric?

A. No. Dr. Woolridge's 8.75 percent ROE recommendation is not fair and reasonable because it is not comparable to returns available from other investments of comparable risk and could have a detrimental effect on the financial integrity of the Company and its ability to access capital on reasonable terms. Furthermore, the rates set in this case, including the ROE and capital structure, will directly affect UNS Electric's cash flows in the period during which rates are in effect. The Company's cash flows, in turn, have a direct bearing on its credit quality and investors' perception of the riskiness of the enterprise. Given this, Dr. Woolridge's recommended ROE of 8.75 percent could exert pressure on the credit metrics that are of the greatest concern to both debt and equity investors. For these reasons, Dr. Woolridge's ROE recommendation is not consistent with the comparability and capital attraction standards established in *Hope* and *Bluefield,* which were discussed in my Direct Testimony.[40]

Q. What are the principal areas of disagreement between you and Dr. Woolridge?

A. As discussed in more detail below, there are several areas in which Dr. Woolridge and I disagree, including: 1) the composition of our respective proxy groups; 2) the growth rates to be applied in the Constant Growth DCF model; 3) the long-term growth rate to be applied in the Multi-Stage DCF model; 4) the market risk premium and the risk free rate inputs to the CAPM; 5) the applicability of the Bond Yield Plus Risk Premium approach; 6) the relevance of market-to-book ratios; 7) the effect of business risks on the Company's ROE; and 8) the appropriate capital structure for UNS Electric.

A. Proxy Group Selection

Q. Please explain your disagreement with Dr. Woolridge regarding the appropriate proxy group for UNS Electric.

A. Dr. Woolridge and I have each developed a proxy group to estimate the Cost of Equity for UNS Electric. However, we have used somewhat different screening criteria in developing our respective proxy groups. Consequently, Dr. Woolridge's proxy group consists of 29 electric utility companies, whereas my initial proxy group was comprised of 13 electric utilities (now reduced to 11 companies due to the exclusion of Southern Company and Duke Energy Corporation).

Q. What is the purpose of a proxy group?

A. An appropriate proxy group consists of companies that are comparable in business and financial risk to UNS Electric. The importance of selecting a proxy group that is similar in overall financial and business risk to the subject company was endorsed by the United States Court of Appeals for the District of Columbia (the "Circuit Court") in the *Petal Gas Storage* decision. The Circuit Court acknowledged that the goal of a proxy group is to rely on companies that possess similar risk to the subject company for the determination of the Cost of Equity:

> That proxy group arrangements must be risk-appropriate is the common theme in each argument. The principle is well-established. See Hope Natural Gas Co., 320 U.S. at 603 ("[T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."); CAPP I, 254 F.3d at 293 ("[A] utility must offer a risk-adjusted expected rate of return sufficient to attract investors."). The principle captures what proxy groups do, namely, provide market-determined stock and dividend figures from public companies comparable to a target company for which those figures are unavailable. CAPP I, 254 F.3d at 293–94. Market determined stock figures reflect a company's risk level and, when combined with dividend values, permit calculation of the "risk-adjusted expected rate of return sufficient to attract investors."

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> What matters is that the overall proxy group arrangement makes sense in terms of relative risk and, even more importantly, in terms of the statutory command to set "just and reasonable" rates, 15 U.S.C. § 717c, that are "commensurate with returns on investments in other enterprises having corresponding risks" and "sufficient to assure confidence in the financial integrity of the enterprise . . . [and] maintain its credit and . . . attract capital," Hope Natural Gas Co., 320 U.S. at 603.[41]

Consistent with the Circuit Court's decision, I have selected a proxy group of companies with comparable investment risk as UNS Electric. In contrast, Dr. Woolridge has applied less stringent screening criteria, which result in a larger, less comparable proxy group. Consequently, there are companies in Dr. Woolridge's proxy group that do not meet the standards established in the *Petal Gas Storage* decision.

Q. Please explain the areas in which you disagree with either Dr. Woolridge's screening criteria or with specific companies in his proxy group.

A. While many of Dr. Woolridge's screening criteria are similar to mine, there are several important differences that affect the composition of our respective proxy groups. First, Dr. Woolridge screens based on the percentage of regulated revenue derived from electric operations rather than the percentage of regulated electric operating income. Since equity investors are primarily concerned with earnings, a net operating income screen is better aligned with the factor that matters most to investors. In addition, the percentage of total revenue can fluctuate considerably from period to period, based on the cost of purchased power or purchased fuel, even though the percentage of operating income is not likely to change as commodity prices fluctuate. Reliance on an operating income screen removes this distortion by excluding large pass-through costs such as the cost of purchased fuel and purchased power that have some, but considerably less, risk than other expense items.

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[41] *Petal Gas Storage v. FERC*, 496 F.3d 695, 699 (D.C. Cir. 2007).

Second, Dr. Woolridge has included several companies in his proxy group that derive more than 30 percent of their operating revenues from natural gas distribution operations, which have a different risk profile than vertically-integrated electric utilities such as UNS Electric. This includes the following companies: Avista Corporation, Black Hills Corporation (which is also involved in a merger with SourceGas), CMS Energy Corporation, and MGE Energy Corporation.

Third, I have concerns with several specific companies that Dr. Woolridge has included in his proxy group. In particular, Dr. Woolridge has included Edison International, First Energy Corp., and PG&E Corp., all of which I excluded from my proxy group due to significant company-specific risk factors that are not reflective of the risks faced by UNS Electric. As discussed in my Direct Testimony, I excluded Edison International from the proxy group due to the ongoing financial implications of the bankruptcy of its subsidiary, Edison Mission Energy.[42] With regard to First Energy Corp., in January 2014, First Energy announced a 35 percent reduction in its dividend. In testimony in other jurisdictions, Dr. Woolridge has previously excluded companies that had reduced or omitted their dividends during the prior three years.[43] However, in this proceeding, Dr. Woolridge has relaxed that screen to six months, which allows him to include First Energy in his proxy group. Finally, I have excluded PG&E Corporation from the proxy group because of the ongoing uncertainty regarding fines and penalties related to the San Bruno incident. Until investors have more certainty with respect to PG&E's liability, it is not appropriate to include PG&E in the proxy group.

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42 Direct Testimony of Ann E. Bulkley, at 20.

43 *See*, for example, Green Mountain Power, Docket No. 8190, submitted March 21, 2014, at 12.

Q. What is your conclusion with respect to the proxy group for UNS Electric?

A. My conclusion is that the proxy group developed in my Direct Testimony (now excluding Southern Company and Duke Energy Corporation) is more risk comparable to UNS Electric than the Woolridge Proxy Group.

B. Constant Growth DCF Analysis

Q. Please summarize the results of Dr. Woolridge's Constant Growth DCF analysis.

A. Dr. Woolridge's Constant Growth DCF analysis produces ROE estimates of 8.70 percent to 9.00 percent, depending on the proxy group.

Q. Have other regulators recognized the value of considering different models to estimate the Cost of Equity as market conditions change?

A. Yes. I recognize that the Commission has traditionally relied primarily on the results of the DCF model. However, as discussed in my Direct Testimony, there are concerns that the DCF models are producing anomalous results under current market conditions.[44] For that reason, I believe it is appropriate to also consider the results of other models as a check on the reasonableness of the DCF results. In addition to the example provided in my Direct Testimony, in Opinion No. 531 the Federal Energy Regulatory Commission ("FERC") recently recognized that the inputs to the DCF model have been affected by anomalous market conditions and therefore for the first time, is considering the use of other ROE estimation models.

> [W]e also understand that any DCF analysis may be affected by potentially unrepresentative financial inputs to the DCF formula, including those produced by historically anomalous capital market conditions. *Therefore, while the DCF model remains the*

[44] Direct Testimony of Ann E. Bulkley, at 18.

> *Commission's preferred approach to determining allowed rate of return, the Commission may consider the extent to which economic anomalies may have affected the reliability of DCF analyses in determining where to set a public utility's ROE within the range of reasonable returns established by the two-step constant growth DCF methodology.*[45]

The FERC indicated that it will look at other ROE estimation methodologies to inform their judgment as to where, within the zone of reasonableness, the ROE should be set. In particular, the FERC found risk premium based approaches, such as the CAPM, informative.

Q. Are the results of Dr. Woolridge's Constant Growth DCF analysis consistent with ROEs awarded recently to electric utility companies?

A. No, as shown in Chart 1, Dr. Woolridge's Constant Growth DCF results are not consistent with the range of authorized ROEs for electric utility companies. Furthermore, Dr. Woodridge's results are not consistent with the results of other ROE estimation models, such as the Multi-Stage DCF, the forward-looking CAPM analysis, or the Bond Yield Plus Risk Premium analysis.

Q. What growth rates does Dr. Woolridge use in his Constant Growth DCF analysis?

A. Dr. Woolridge arrives at growth rate estimates of 4.75 percent for his proxy group and 5.0 percent for the Bulkley Proxy Group.[46] Dr. Woolridge's growth rates are based on consideration of both historical and projected growth in EPS, as well as historical and projected dividends per share ("DPS") and book value per share ("BVPS"), and the internal growth rate. Dr. Woolridge obtains projected EPS growth rates from Value

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45 147 FERC ¶ 61,234, para. 41. (Emphasis added.)

46 Direct Testimony of Dr. J. Randall Woolridge, at 21.

Line, Yahoo! Finance, Zacks, and Reuters, and all other historical and projected DPS, BVPS, and internal growth rates from Value Line.

Q. How does Dr. Woolridge select the growth rate estimates he has used in his Constant Growth DCF model?

A. Dr. Woolridge's growth rate estimates appear to be subjectively set within the range for each proxy group. Dr. Woolridge states that he has given "primary weight to the projected EPS growth rate of Wall Street analysis,"[47] but the weight he has ascribed to projected EPS growth rates is unclear and is inconsistent between proxy groups. For his proxy group, Dr. Woolridge finds that the range of "projected growth rate indicators (ignoring historical growth)" is from 4.20 percent (equal to Value Line's projected mean BVPS growth rates) to 4.80 percent (equal to Value Line's projected mean DPS growth rates and Zack's projected EPS growth rate).[48] For the Bulkley proxy group, Dr. Woolridge finds that the range of growth rates is from 3.50 percent (equal to Value Line's 10-year historical mean BVPS growth rate and Value Line's projected sustainable growth rate) to 5.20 percent (which corresponds to the mean consensus projected EPS growth rates from Zack's, Reuters, and Yahoo! Finance).[49]

Q. Do you agree with Dr. Woolridge that "there are several issues with using the EPS growth rate forecasts of Wall Street analysts as DCF growth rates"?[50]

A. No, I strongly disagree with Dr. Woolridge on this point. As discussed in my Direct Testimony, earnings are the fundamental determinant of a company's ability to pay dividends.[51] Further, both dividends and book value per share may be directly affected

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47 *Ibid.*
48 *See* Exhibit JRW-10.
49 *Ibid.*
50 Direct Testimony of Dr. J. Randall Woolridge, Appendix D, at D-15.
51 Direct Testimony of Ann E. Bulkley, at 25.

by short run management decisions. As a result, dividend growth rates and book value growth rates may not accurately reflect a company's long-term growth. In contrast, earnings growth is not affected by short run cash management decisions.

In addition, EPS growth rates are the only forward-looking growth rates available on a consensus basis. With the exception of his EPS growth rates, the source for all of Dr. Woolridge's growth rates is Value Line. Dr. Woolridge's reliance on Value Line's historical and forecasted DPS and BVPS growth rates, as well as Value Line's estimates of ROE and retention rates for his internal growth rate, unnecessarily introduces "sole source" bias into his calculations. By contrast, my Constant Growth DCF analysis is based on forecasted EPS growth rates from multiple sources, including Zack's and Thomson First Call, both of which provide consensus estimates from multiple analysts.

Q. Do you share Dr. Woolridge's concern that "long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased"?[52]

A. No, I do not. Dr. Woolridge has provided no evidence that the growth rates for the companies in my DCF analysis are the result of consistent and pervasive analyst bias. Moreover, the 2003 Global Analysts Research Settlement (the "Global Settlement") served to significantly reduce the bias referred to by Dr. Woolridge. In fact, the Global Settlement required financial institutions to insulate investment banking from analysis, prohibited analysts from participating in "road shows," and required the settling financial institutions to fund independent third-party research. In addition, analysts covering the common stock of the proxy companies certify that their analyses and recommendations are not related, either directly or indirectly, to their compensation. Thus, it is unclear why investors would assume that the proxy companies are susceptible to a continuing upward bias in earnings projections.

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[52] Direct Testimony of Dr. J. Randall Woolridge, Appendix D, at D-16.

A 2010 article in Financial Analysts Journal found that analyst forecast bias declined significantly or disappeared entirely since the Global Settlement:

> Introduced in 2002, the Global Settlement and related regulations had an even bigger impact than Reg FD on analyst behavior. After the Global Settlement, the mean forecast bias declined significantly, whereas the median forecast bias essentially disappeared. Although disentangling the impact of the Global Settlement from that or related rules and regulations aimed at mitigating analysts' conflicts of interest is impossible, forecast bias clearly declined around the time the Global Settlement was announced. These results suggest that the recent efforts of regulators have helped neutralize analysts' conflicts of interest.[53]

Q. Do you agree with Dr. Woolridge that historical measures of growth are relevant to a forward-looking evaluation of the Company's ROE?

A. No, I do not. The Constant Growth and Multi-Stage DCF models are both forward-looking models that evaluate investors' required returns based on future cash flows. As such, the appropriate measure of growth to incorporate for DCF analyses is investors' expectations, not historical results. Dr. Woolridge himself observes that historical growth rates must be treated with caution because "in some cases, past growth may not reflect future growth potential."[54] In addition, securities' analysts forecasted growth rates incorporate historical performance to the extent the analysts believe it is likely to continue. Additional consideration of historical growth rates, therefore, provides no meaningful incremental information regarding the proxy companies' future growth potential.

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

[54] Direct Testimony of J. Randall Woolridge, Appendix D, at D-13.

Q. Do you agree with Dr. Woolridge's use of retention growth rates as measured by the product of earnings retention ratios and earned returns on common equity?

A. No, I do not. Dr. Woolridge's calculation of retention growth rates (also known as "internal growth rates" or "sustainable growth rates") considers only the product of earnings retention rates and earned returns on common equity, or what are commonly known as internally-generated funds. In the sustainable growth formula, this is commonly referred to as the product of "b X r", where "b" is the retention ratio or the portion of net income not paid in dividends, and "r" is the expected ROE on the portion of net income that is retained within the Company as a means for future growth.

Dr. Woolridge fails to consider that earnings growth also occurs as a result of new equity issuances, or what are commonly known as externally-generated funds. In the sustainable growth formula, this is shown as the product of "s X v", where "s" represents the growth in shares outstanding and "v" is that portion of the M/B ratio that exceeds unity. This methodology is recognized as a common approach to calculating the sustainable growth rate.[55] By only considering the funds from internally-generated sources, Dr. Woolridge's sustainable growth rate calculation understates the prospective growth rates for his proxy group companies. As shown on Exhibit AEB-R-10, had Dr. Woolridge included the "s X v" component in his computation, his median sustainable growth rate would increase by approximately 20 basis points from 4.20 percent to 4.40 percent.

[55] *See* Roger Morin, New Regulatory Finance, at 306.

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

A. Yes. In Opinion No. 531, the FERC changed its approach on the DCF methodology to be applied in public utility rate cases.[56] In summary, the FERC adopted the same two-step DCF methodology it has employed in gas and oil pipeline rate proceedings since the mid-1990s, in place of the one-step methodology previously used. The FERC's two-stage DCF approach does not rely on a sustainable growth calculation.

Q. Do you have other concerns with the reasonableness of Dr. Woolridge's sustainable growth rate calculation?

A. Yes, I do. Since the "r" in the "b x r" approach refers to the ROE, Dr. Woolridge has effectively pre-supposed Value Line's ROE and payout ratio projections for his proxy group companies. By using this growth measure, Dr. Woolridge has assumed the reasonableness of Value Line's ROE projections, yet, as shown on Dr. Woolridge's Exhibit JRW-10, page 4, the mean and median ROE projections for the electric utility companies in his proxy group are 10.2 percent and 9.5 percent, respectively, which is significantly higher than his recommended ROE for UNS Electric of 8.75 percent.

Q. What would be the average growth rate for Dr. Woolridge's proxy group companies if he had used only analysts' forecasted, positive EPS growth rates?

A. As shown in Exhibit AEB-R-11, if Dr. Woolridge had used only analysts' forecasted EPS growth rates for his proxy group companies, and if he had excluded negative EPS growth rate projections for proxy companies that are not involved in mergers or

[56] Opinion No. 531 147 FERC ¶ 61,234 (June 19, 2014).

transformative transactions, his median growth rate would be 5.50 percent rather than 4.80 percent.

C. Multi-Stage DCF Model

Q. Has Dr. Woolridge performed a Multi-Stage DCF analysis to estimate the Cost of Equity for UNS Electric?

A. No, he has not. While Dr. Woolridge recognizes that the Dividend Discount Model or three-stage model is commonly used to estimate the Cost of Equity, he does not develop recommendations based on either of these forms of the DCF model.[57]

Q. Please summarize Dr. Woolridge's criticisms of the assumptions relied on in your Multi-Stage DCF model.

A. Dr. Woolridge does not take issue with the near-term growth rates (*i.e.*, analysts' forecasts of EPS growth) used in my Multi-Stage DCF model. However, he asserts that the long-term growth rate I have used is "clearly inflated."[58] In support of this assertion, Dr. Woolridge points to recent trends in GDP growth that he states suggest that "nominal GDP growth in recent decades has slowed."[59]

Q. Please summarize Dr. Woolridge's criticism of your long-term growth rate.

A. Dr. Woolridge disagrees with the use of a long-term historical estimate of GDP growth, stating that there is no empirical or theoretical support for the use of that time period. Dr. Woolridge presents, in Table 4 of his testimony, five shorter term averaging periods for GDP growth, demonstrating a range from 6.8 percent to 3.9 percent. Dr. Woolridge

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57 Direct Testimony of Dr. J. Randall Woolridge, Appendix D, at D-9.
58 Direct Testimony of Dr. J. Randall Woolridge, at 34.
59 *Ibid.*

concludes that economic growth in more recent historical periods has been lower than the long-term historical average.

Q. How do you respond to this criticism?

A. Investors understand that the U.S. economy goes through cycles of growth and contraction. It is not appropriate to exclude certain periods simply because economic growth was unusually weak or strong. Rather, as Morningstar explains, it is appropriate to use the longest time period possible to measure historical real growth in GDP:

> Growth in real GDP (with only a few exceptions) has been reasonably stable over time; therefore, its historical performance is a good estimate of expected long-term future performance. By combining the inflation estimate with the real growth rate estimate, a long-term estimate of nominal growth is formed…[60]

In response to Dr. Woolridge's desire to use a more recent period to measure GDP growth, I agree with Morningstar's view on this issue as well. They write:

> The 87-year period starting with 1926 is representative of what can happen: it includes high and low returns, volatile and quiet markets, war and peace, inflation and deflation, and prosperity and depression. Restricting attention to a shorter historical period underestimates the amount of change that could occur in a long future period. Finally, because historical event-types (not specific events) tend to repeat themselves, long-run capital market return studies can reveal a great deal about the future. Investors probably expect "unusual" events to occur from time to time, and their return expectations reflect this.[61]

Q. Dr. Woolridge states that economists and various government agencies are forecasting lower GDP growth rates.[62] What is your response?

A. Nominal GDP growth rates of 4.20 percent to 4.70 percent, as published in the reports cited by Dr. Woolridge, are well below the average nominal GDP growth rate in the

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60 Ibbotson and Associates, Stocks, Bonds, Bills and Inflation, 1926-2012, 2013 Valuation Yearbook, at 52.
61 *Ibid.*, at 59.
62 Direct Testimony of Dr. J. Randall Woolridge, at 35.

U.S. since 1929. By comparison, my historical GDP growth rate of 5.40 percent is based on a projected inflation rate of 2.09 percent (based on three sources), and actual historical growth in real GDP of 3.25 percent from 1929-2014.

Moreover, as discussed in my Direct Testimony, there has been a tendency to under-estimate GDP growth in the decade after severe economic events.[63] The financial crisis and recession that began in 2007 were qualitatively different from most other U.S. economic downturns, which were followed by a rapid return to pre-recession overall output growth levels. The current U.S. economic growth situation is similar to that following the two most severe economic events in U.S. history (*i.e.*, the 1929 stock market crash and the 1973 oil shock).

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

A. In my view, current estimates of real GDP growth are understated relative to the long-term average because forecasters are placing too much weight on recent economic weakness. For that reason, I believe that it is reasonable to use historical long-term GDP growth as the terminal growth rate in the Multi-Stage DCF model, as I have done. However, the Multi-Stage DCF model does not directly reflect the substantial increase in interest rates that is projected over the next five years, as borrowing costs increase from the artificially low levels of the recent past. For that reason, it is also appropriate to consider the results of a forward-looking CAPM analysis, because that model is more sensitive to expected changes in interest rates.

[63] Direct Testimony of Ann E. Bulkley, at 28-29.

D. CAPM Analysis

Q. Please summarize Dr. Woolridge's CAPM results and explain how he uses that analysis.

A. As shown in Table 2 of Dr. Woolridge's Direct Testimony, his CAPM results are 8.10 for the Woolridge Proxy Group and 8.30 percent for the Bulkley Proxy Group. These results are based on a risk free rate of 4.00 percent, a Beta coefficient between 0.75 and 0.78, and a MRP of 5.50 percent. The results of Dr. Woolridge's CAPM analysis form the lower boundary of his range of results for UNS Electric. Dr. Woolridge testifies that he ultimately relies primarily on the results of his Constant Growth DCF model.[64] The results of Dr. Woolridge's CAPM analysis are well below the authorized ROE for any U.S. electric utility company in the past 25 years.[65]

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

A. I have two areas of concern with the inputs and assumptions that Dr. Woolridge has relied on to derive his CAPM results. First, I do not believe that Dr. Woolridge's risk free rate of 4.00 percent adequately considers projected increases in Treasury bond yields. Second, I take issue with Dr. Woolridge's use of an MRP of 5.50 percent because it is based on the results of investor surveys and academic research rather than forward-looking market data, and does not reflect the inverse relationship between interest rates and the equity risk premium.

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64 Direct Testimony of Dr. J. Randall Woolridge, at 26.

65 Source: Regulatory Research Associates.

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

A. The inputs and assumptions used in the ROE analysis should reflect the forward-looking Cost of Equity. As discussed in Section III of my Rebuttal Testimony, leading economists surveyed by Blue Chip are expecting a substantial increase in long-term interest rates over the next five years. This is a very important consideration for equity investors as they assess their return requirements. Dr. Woolridge attempts to take into consideration the prospect for higher interest rates by choosing a risk free rate of 4.00 percent, which is approximately half-way between the current yield on 30-year Treasury bonds and their projected yield of 4.80 percent for the period from 2017-2021.[66] However, I do not believe that Dr. Woolridge's risk free rate of 4.00 percent adequately takes into consideration the effect of the market's expectation for higher interest rates on the Cost of Equity for UNS Electric. For that reason, I believe that Dr. Woolridge's CAPM results are understated.

Q. What MRP does Dr. Woolridge use in his CAPM analysis?

A. Dr. Woolridge estimates the MRP as being in the range of 4.00 percent to 6.00 percent. From within that range, he chooses an MRP of 5.50 percent.[67]

Q. What is the basis for Dr. Woolridge's MRP of 5.50 percent?

A. Dr. Woolridge, measures the equity risk premium as the difference between historical average stock and bond returns based on information reported by Ibbotson and Associates.[68] Dr. Woolridge notes that most historical assessments of the equity risk premium were in the range of 5.0 percent to 7.0 percent above the rate on long-term

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66 Blue Chip Financial Forecasts, Vol. 34, Issue No. 6, June 1, 2015, at 14.
67 Direct Testimony of Dr. J Randall Woolridge, at 25.
68 *Ibid.,* Appendix D, at D-21.

U.S. Treasury bonds. However, Dr. Woolridge states that the use of historical MRPs can be problematic because MRPs can change over time, and market conditions can change such that historical returns are poor estimates of future returns.[69]

The other way to measure the MRP, according to Dr. Woolridge, is to rely on investor surveys and the results of academic research.[70] Dr. Woolridge presents the results of several surveys that have been published since January 2010. The median MRP reported in those surveys is 4.82 percent.[71] In particular, Dr. Woolridge highlights a 2015 survey of expected market returns of academics, financial analysts and companies which included over 4,000 responses. The median equity risk premium for U.S. companies derived from the Fernandez survey was 5.50 percent.[72]

Q. What is your concern with Dr. Woolridge's MRP estimate of 5.50 percent?

A. Given the current low yields on Treasury bonds, and the inverse relationship between interest rates and the MRP, my concern is that Dr. Woolridge's MRP estimate of 5.50 percent is understated. The average historical income only return on long-term government bonds that is used to calculate the historical MRP is 5.18 percent, while the current 30-day average risk free rate on long-term government bonds is approximately 2.98 percent.[73] The historical MRP as reported by Ibbotson and Associates is 7.0 percent through 2014. Because interest rates on long-term government bonds are well below the historical average of 5.18 percent, the inverse relationship between interest rates and the MRP implies that the forward-looking MRP should be higher than 7.0 percent.

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69 *Ibid.*

70 *Ibid.*, at D-22.

71 Exhibit JRW-11, page 6 of 6.

72 Direct Testimony of Dr. J. Randall Woolridge, Appendix D, at D-25.

73 Using the regression equation in AEB-R-6, I calculated the ROE at the current 30-day average risk free rate and the average historical risk free rate. Using the current 30-day average risk free rate of 2.98% as compared to the historical average risk free rate of 5.18% results in an understatement of the ROE of approximately 96 basis points. (9.87% vs. 10.83%).

Q. Do you have any concerns regarding the investor surveys that Dr. Woolridge has relied upon to derive his range of 4.00 percent to 6.00 percent for the MRP?

A. Yes. Neither the Philadelphia Federal Reserve survey nor the Duke University/CFO magazine survey asks participants to provide their expected MRP. Instead, both surveys ask participants for expected returns on stocks and bonds without defining what is meant by "returns." To the extent that "return" does not include both income (dividend yield) and growth (capital appreciation), the survey results may understate the expected total return of survey respondents.

According to Dr. Woolridge, the February 2015 survey by the Philadelphia Fed reports that the median long-term expected stock return is 5.79 percent. That return is generally consistent with the GDP and EPS growth rates shown in Table 5 of Dr. Woolridge's Direct Testimony. The returns in Table 5 represent growth in the S&P 500 stock prices and the growth rate of nominal GDP and S&P 500 earnings per share. The Philadelphia Fed's survey does not specify whether the expected returns for the S&P 500 represent total returns or only capital appreciation. To the extent the Philadelphia Fed survey includes only capital gains and not dividends, the survey understates the actual return that investors expect, which, in turn, suggests the MRP that Dr. Woolridge calculates using this data is understated because the long-term growth rate for the S&P 500 is understated. Further, as shown in Exhibit JRW-11, the Philadelphia Fed survey considered the responses of 20 financial forecasters with regards to the expected returns for the S&P 500; however, about 40 financial forecasters participated in the 2015 first quarter survey, meaning that approximately half (i.e., 19) of the survey participants did not respond to the specific question on market returns.[74]

[74] Survey of Professional Forecasters, Philadelphia Federal Reserve, February 13, 2015, at 17.

Similarly, the Global Business Outlook Survey conducted quarterly by Duke University and CFO magazine asks participants to predict the average annual return for the S&P 500 over the next ten years given the current annual yield on ten-year Treasury bonds. CFO magazine uses this information to estimate the MRP by subtracting the current yield on ten-year Treasury bonds from the expected return on the S&P 500. As with the Philadelphia Fed survey, the Duke survey asks respondents for expectations regarding the "average annual S&P 500 return," but does not define return.[75] Moreover, while the Duke survey addresses return expectations (however defined), it does not ask whether the respondents would be willing to invest (*i.e.*, meets their required return expectations) in equity at those return levels. To the extent that expected and required returns differ, the usefulness of survey responses for the purpose of establishing UNS Electric's required ROE becomes increasingly tenuous.

Q. Have others also expressed concerns with the use of investor surveys to estimate the equity risk premium?

A. Yes. For example, Finance Professor Aswath Damodoran, who has published extensively on the question of how to estimate the equity risk premium, discussed his concerns with using investor surveys to estimate the equity risk premium:[76]

While survey premiums have become more accessible, very few practitioners seem to be inclined to use the numbers from these surveys in computations and there are several reasons for this reluctance:

> 1. Survey risk premiums are responsive to recent stock price movements, with survey numbers generally increasing after bullish periods and decreasing after market declines…;
>
> 2. Surveys premiums are sensitive not only to whom the question is directed at but how the question is asked. For example, asking the question, "What do you think stocks will do next year?" generates

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[75] *See* CFO Magazine Survey, Q2-15, Section 9.

[76] Aswath Damodoran, *Equity Risk Premiums (ERP): Determinants, Estimation, and Implications – The 2013 Edition*, Updated March 2013, at 19-20.

different numbers than asking, "What should the risk premium be for investing in stocks?";

3. In keeping with other surveys that show differences across sub-groups, the premium seems to vary depending on who gets surveyed…; and

4. Studies that have looked at the efficacy of survey premiums indicate that if they have any predictive power, it is in the wrong direction...

Dr. Damodoran ultimately concludes that "it is also likely that these survey premiums will be more reflections of the recent past than good forecasts of the future."[77]

Q. What is Dr. Woolridge's concern with the MRPs you have used in your CAPM analysis?

A. Dr. Woolridge is concerned that my forward-looking MRP is over-stated because it was developed using the expected return for the S&P 500 based on analysts' forecasted EPS growth rates. In particular, Dr. Woolridge testifies: "The bottom line is that Ms. Bulkley's estimated expected stock market return of 13.19% is not realistic."[78] Dr. Woolridge also incorrectly states that I have only used a projected MRP of 10.67 percent in my CAPM analysis.[79]

Q. Does Dr. Woolridge agree that the MRP can be estimated based on expected returns for the S&P 500?

A. Yes. According to Dr. Woolridge: "The MRP is the difference in the expected total return between investing in equities and investing in "safe" fixed income assets, such as long-term government bonds."[80] Dr. Woolridge states that the expected total return for

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77 *Ibid.*, at 20.
78 Direct Testimony of Dr. J. Randall Woolridge, at 37.
79 *Ibid.*, at 5.
80 *Ibid.*, at D-20.

the market is often measured by reference to the S&P 500.[81] This is consistent with the approach I have used to estimate the forward-looking MRP in my CAPM analysis.

Q. What is your response to Dr. Woolridge's concern about your forward-looking MRP?

A. Dr. Woolridge expresses concern that the forward-looking MRP in my CAPM analysis is based on five-year EPS growth rates from Wall Street analysts, which he claims are "overly optimistic and upwardly biased."[82] He supports this assertion by arguing that the EPS growth rate for the S&P 500 of 11.06 percent is significantly higher than long-term nominal GDP growth and long-term EPS growth for the S&P 500.[83] However, the analysts' forecasted growth rates are market-based growth rates upon which current stock prices for the companies in the S&P 500 are based. In other words, 13.19 percent is not my estimate of the expected market return; it is based on market data such as forecasted earnings growth rates and dividend yield for the companies in the S&P 500. Dr. Woolridge supports the use of the Constant Growth DCF model to estimate the Cost of Equity for UNS Electric. Yet, he dismisses the expected five-year EPS growth rates as overly-optimistic even though the model upon which he relies assumes that investors set stock prices based on expectations for future growth in dividends and share price. As discussed previously in my Rebuttal Testimony, recent academic research has found that analyst bias has been reduced or eliminated, if it ever existed, after the financial market reforms of the early 2000s.

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81 *Ibid.*

82 Direct Testimony of Dr. J. Randall Woolridge, at 51.

83 *Ibid.*, at 38.

Q. What is your conclusion regarding the appropriate MRP in the context of current market data?

A. My conclusion is that Dr. Woolridge's estimated MRP of 5.50 percent is substantially lower than (1) the historical MRP using large company stocks (7.0 percent); and (2) the forward-looking MRP in my updated CAPM analysis, which was derived using forecasted total returns for the S&P 500 less the risk free rate (between 8.71 percent and 10.53 percent). Dr. Woolridge's MRP of 5.50 percent, when added to the 30-day average yield on the 30-year Treasury as of November 30, 2015 of 2.98 percent, suggests that market participants are expecting a total return for equities of around 8.48 percent. By contrast, the long-term average total return for large company stocks since 1926, as reported by Morningstar, has been 12.1 percent, or approximately 360 basis points higher than Dr. Woolridge's MRP estimate assumes. For these reasons, I continue to support the method I used to estimate the MRP.

E. Bond Yield Plus Risk Premium Method

Q. Please summarize Dr. Woolridge's concerns with your Risk Premium analysis.

A. Dr. Woolridge has expressed several concerns with my Bond Yield Plus Risk Premium analysis, including: (1) that I have used historical authorized ROEs and Treasury yields and applied the resulting risk premium to projected Treasury yields; (2) that the analysis is a gauge of regulatory commission behavior, not investor behavior; and (3) that my analysis includes returns from settled as well as litigated rate cases.[84]

[84] *Ibid.*, at 77-78.

Q. Does your Risk Premium analysis only apply a historical risk premium to a projected Treasury yield?

A. No, it does not. As shown in Exhibit AEB-R-6, my Risk Premium analysis determines the appropriate risk premium based on the relationship between historic authorized ROEs and bonds yields. I derive three separate estimates of the ROE based on this analysis, which forms the range of my results. I also disagree with Dr. Woolridge that it is incorrect to apply the historical risk premium from this analysis to current and projected Treasury yields in order to estimate the ROE at specified interest rates.

Q. What is your response to Dr. Woolridge's concern that your Risk Premium analysis is a gauge of regulatory commission behavior rather than investor behavior?

A. While my Risk Premium analysis is based on authorized ROEs and the corresponding Treasury yields at the time the regulatory decisions were issued, I believe that investors are informed by allowed ROEs from hundreds of rate case decisions to frame their return expectations. One of the fundamental principles in setting a just and reasonable return is that the return must be comparable to returns available to investors in companies with commensurate risk. In that regard, the returns that have been authorized to other electric utility companies are a relevant consideration for investors. My Risk Premium analysis simply shows what those returns are in relation to the risk free rate, so that it is possible to use historical returns to estimate future returns given investor expectations as shown by current and projected Treasury yields.

Q. Do you share Dr. Woolridge's concern that your Risk Premium analysis includes settled rate case decisions?

A. No, I do not. In order to test Dr. Woolridge's premise that settled rate decisions are different than litigated rate decisions, I performed my Risk Premium analysis for

electric utility companies for the period from 1992 through February 28, 2015 using only litigated cases. Based on that analysis, as shown on Exhibit AEB-R-12, the resulting ROE estimate ranges from 9.69 percent to 10.76 percent, with an average of 10.15 percent. As such, there is no basis for Dr. Woolridge's concern that the inclusion of settled rate case decisions impacted my Risk Premium analysis.

Q. What is your conclusion regarding the Risk Premium analysis?

A. I continue to support the use of the Risk Premium analysis to corroborate the reasonableness of my DCF and CAPM results.

F. Relevance of Market-to-Book Ratios

Q. Please summarize Dr. Woolridge's position regarding the relationship between the Market-to-Book ("M/B") ratio and authorized equity returns.

A. Dr. Woolridge states that a M/B ratio above 1.0 indicates that the company is earning a return "above its Cost of Equity."[85] Dr. Woolridge further asserts that there is a strong positive relationship between the estimated ROE and M/B ratios for public utilities, based on a regression analysis he performed using Value Line data.[86]

Q. What is the M/B ratio?

A. The M/B ratio equals the market value (or stock price) per share divided by the total common equity (or the "book equity") per share. Book value per share is an accounting construct which reflects historical costs. In contrast, market value per share (*i.e.*, the stock price) is forward-looking and is a function of many variables, including (but not

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85 Direct Testimony of Dr. J. Randall Woolridge, Appendix D, at D-2 through D-3.

86 *Ibid,* at D-4.

limited to) expected earnings and cash flow growth, expected payout ratios, measures of "earnings quality," the regulatory climate, the equity ratio, expected capital expenditures, and the expected return on book equity.[87] It follows, therefore, that the M/B ratio is also a function of numerous variables in addition to the historical or expected return on book equity.

Q. Do you agree with Dr. Woolridge that utility companies with M/B ratios above 1.0 are earning returns above their Cost of Equity?

A. No, I do not. I have several concerns with Dr. Woolridge's position. Chart 4 shows the M/B ratio for companies in Dr. Woolridge's proxy group for the period January 1, 2005 through December 31, 2014. Over that period, the proxy group average (represented by the dotted line) was 1.49. Even though the proxy group companies were subject to numerous ROE awards during that period, I am not aware of any state regulatory commission that has set the authorized ROE for a public utility based on a M/B ratio of 1.0. The only time during this period that the M/B ratio for the Woolridge proxy group approached 1.0 was during the Great Recession, clearly not an indicator of normal market conditions. Based on this evidence, it appears that state regulatory commissions do not share Dr. Woolridge's concern that such companies are earning returns in excess of their required returns, and that authorized returns should be set at levels that force the M/B ratio to unity.

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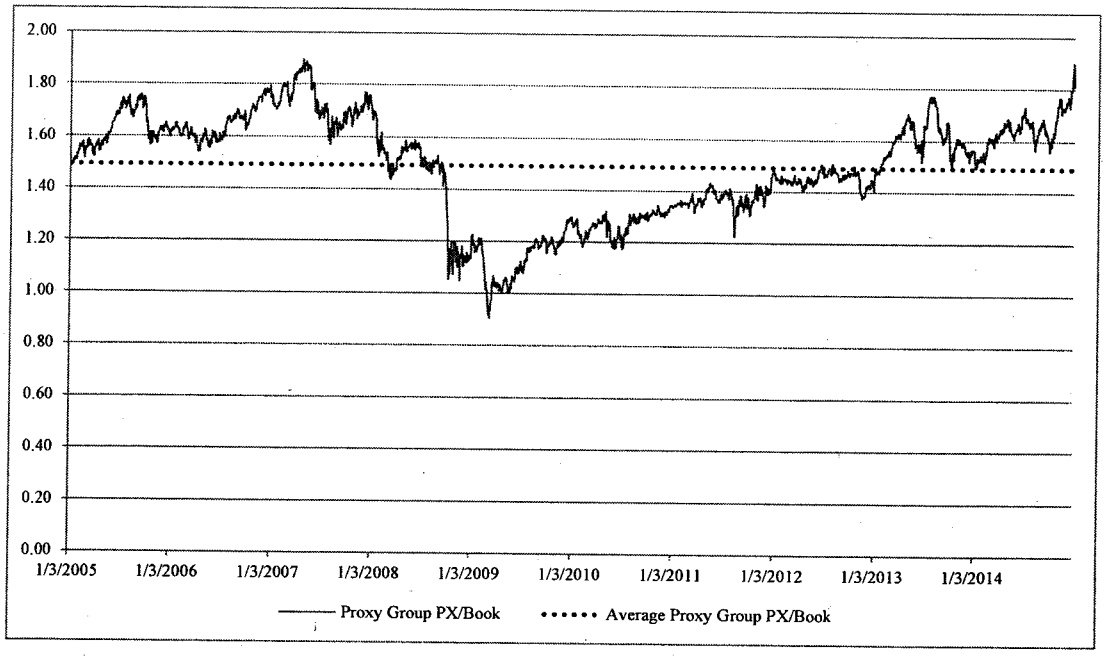
[87] *See* Roger A. Morin, New Regulatory Finance, Public Utilities Reports, Inc., 2006 at 366.

Chart 4: Proxy Group Average Market-to-Book Ratio[88]



Further, the notion that book values should be set at unity by regulatory commissions has been refuted for many years. As noted by Stewart Meyers in 1972:

> In short, a straightforward application of the cost of capital to a book value rate base does not automatically imply that the market and book values will be equal. This is an obvious but important point. If straightforward approaches did imply equality of market and book values, then there would be no need to estimate the cost of capital. It would suffice to lower (raise) allowed earnings whenever markets were above (below) book.[89]

Q. What would be the practical effect of setting an allowed ROE for utility stocks that reduced the M/B ratio to 1.0?

A. As a practical matter, no rational investor would invest in utility stocks if they believed that utility commissions would set rates in an effort to move the M/B ratio to unity. If, for example, an investor purchased a utility stock at the long-term average M/B ratio of 1.49 (*i.e.*, the proxy group average), that investor would incur a loss of approximately

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88 Source: Bloomberg.

89 Stewart C. Meyers, *The Application of Finance Theory to Public Utility Rate Cases*, The Bell Journal of Economics and Management Science, Vol. 2, No. 1 (Spring, 1972) at 76.

33 percent once the ratio reached unity (1.00 / (1.49 – 1) = -32.98%). Such a result would impede a utility's ability to attract the capital required to support its operations, in direct contravention of the *Hope* and *Bluefield* standards.

Q. Are you aware of any contemporary text suggesting that M/B ratios for utilities should be expected to revert to 1.0?

A. No. To the contrary, Dr. Roger Morin provides an extensive review of the issue of M/B reversion to unity and makes the following summation:

> In short, economic principles do not support the notion that the market value of utility shares should necessarily equal book value. A basic economic principle holds that, in the long run, market value should equal asset replacement cost in a given industry. In the presence of inflation and absent significant technological advances, replacement cost exceeds the original cost book value of assets. Consequently it is quite reasonable for the market value of utility shares to exceed their book value and there is no reason to conclude that market value should equal book value when one recognizes that regulation is intended to emulate competition.[90]

Q. What is your conclusion regarding the relevance of M/B ratios in setting the allowed ROE for UNS Electric in this proceeding?

A. My conclusion is that investors do not expect allowed returns for utilities to be set at levels that would cause the M/B ratio to approximate unity. Such returns would provide unreasonably low equity risk premia and are inconsistent with prevailing levels of authorized ROEs for comparable risk electric utilities. Dr. Woolridge's own regression analysis demonstrates that the market is expecting higher returns on equity than what he is recommending for UNS Electric in this proceeding. For all of these reasons, the Commission should not be concerned with setting the allowed ROE for UNS Electric in this proceeding at a level that would cause the M/B ratio to move toward unity.

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90 *See*, New Regulatory Finance, Roger A. Morin Ph.D., Public Utility Reports, 2006, at 376 - 378.

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2 **G. Adjustment for Business Risk**

3 **Q. Has Dr. Woolridge adjusted his recommended ROE for UNS's business risk?**

4 A. No, Dr. Woolridge has not adjusted his DCF and CAPM results to account for UNS
5 Electric's above-average risk relative to the proxy group. As discussed in my Direct
6 Testimony, UNS Electric's projected capital expenditures will remain elevated over
7 time which increases its overall risk.[91] This is especially important due to the fact that
8 UNS Electric is much smaller than the average proxy group company, which means that
9 investors' return requirements are higher. While I did not adjust my ROE
10 recommendation for any of these risks individually, I did take them into consideration
11 in aggregate when selecting the appropriate ROE for UNS Electric. Specifically, based
12 on UNS Electric's higher risk on these factors, my recommendation falls above the
13 midpoint of my range of results, but well within the range.

14

15 **Q. Do you agree with Dr. Woolridge that the small size of UNS Electric does not**
16 **support an authorized ROE above the proxy group average?**

17 A. No, I do not. Dr. Woolridge contends that there is no need for a size adjustment or
18 premium because: 1) a company's credit rating reflects the risk associated with the size
19 of the company; 2) the size premium is based on historical returns which are upwardly
20 biased measures of expected risk premiums; and 3) empirical studies show that size
21 premiums are not required for utilities.[92]

22 Dr. Woolridge, however, fails to take into consideration that the authorized ROE for UNS
23 Electric should be set on a stand-alone basis. In other words, the stand-alone principle
24 requires that the authorized return be set at a level that allows the company on a stand-

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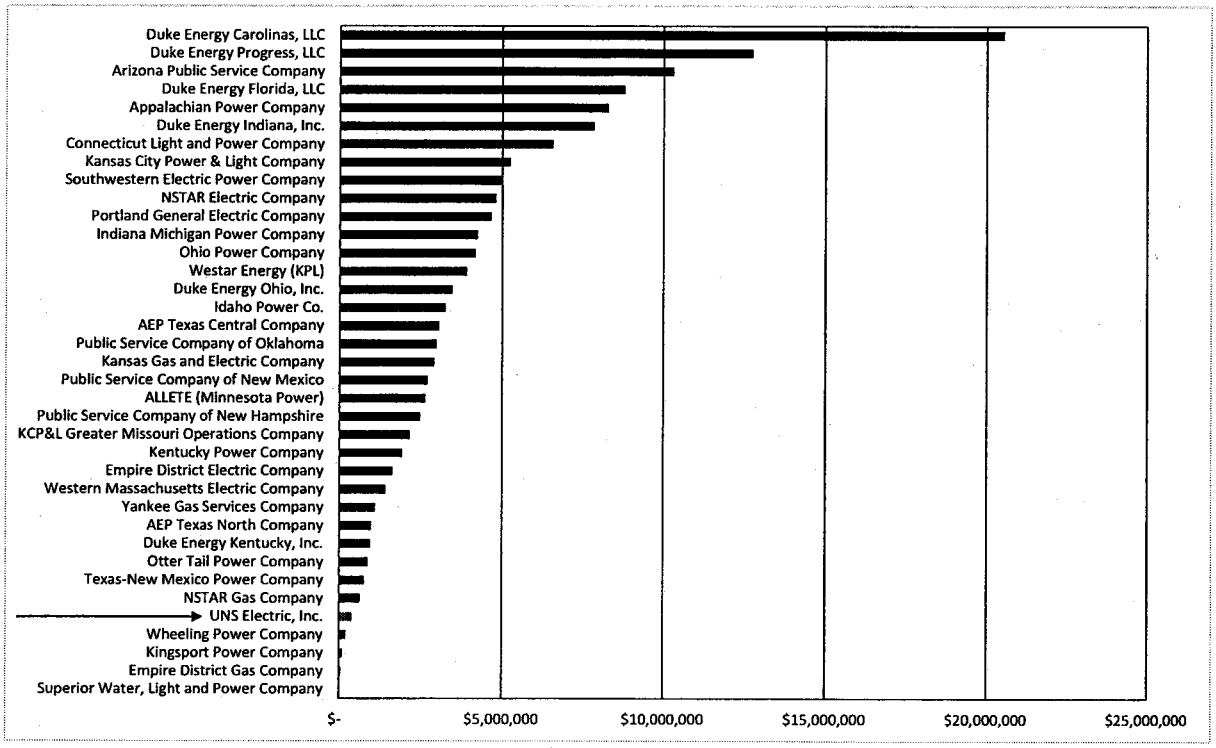
91 Direct Testimony of Ann E. Bulkley, at 43.
92 Direct Testimony of Dr. J. Randall Woolridge, at 44.

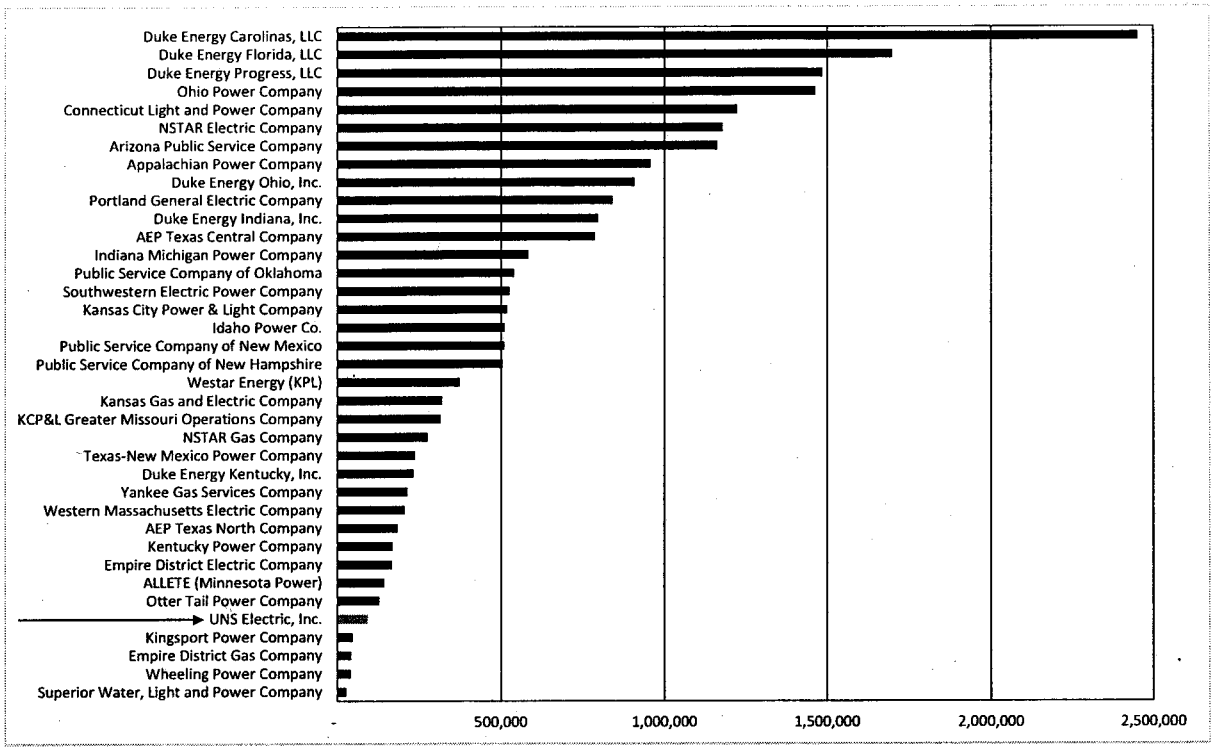
alone basis to attract capital. As discussed in my Direct Testimony, UNS Electric is substantially smaller than the proxy group companies. As shown in Charts 5 and 6 below, UNS Electric is also smaller in terms of both net utility plant and customers than all but four of the 36 operating companies that are held by the proxy group companies. Even on this basis, UNS Electric is much smaller than average, which supports an authorized ROE above the proxy group average.

Chart 5: Comparison of 2014 Net Plant ($000)[93]



[93] Source: SNL Energy, Inc.

Chart 6: Comparison of 2014 Customer Count[94]



H. Proposal to Impute Capital Structure

Q. Please summarize Dr. Woolridge's proposed adjustment to UNS Electric's capital structure.

A. Dr. Woolridge proposes an imputed capital structure consisting of 50.0 percent common equity and 50.0 percent long-term debt, as compared to UNS Electric's actual test year capital structure of 52.83 percent common equity and 47.17 percent long-term debt.[95] Dr. Woolridge states that the Company's requested capital structure does not reflect the capital structures of companies in the Woolridge or Bulkley proxy groups or the parent company of UNS Electric, Fortis, Inc.[96] In particular, Dr. Woolridge testifies that the median common equity ratio for the companies in the Woolridge and Bulkley proxy

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94 Source: SNL Energy, Inc.

95 Direct Testimony of Dr. J. Randall Woolridge, at 5.

96 *Ibid.*, at 26-27.

groups is 47.7 percent and 49.3 percent, respectively.[97] On that basis, he concludes that a hypothetical capital structure is more appropriate.

Q. Have any of the other ROE witnesses in this proceeding recommended an adjustment to UNS Electric's proposed capital structure?

A. No, they have not. In fact, Mr. Mease explicitly testifies that he supports the Company's proposed capital structure as reasonable because it is consistent with the capital structures of his proxy group companies.[98]

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

A. Yes. The AUS report that Dr. Woolridge relies on for his analysis of the proxy company capital structures reports the holding company capital structures.

Q. Do you agree with Dr. Woolridge's analysis of the capital structure?

A. No, I do not. The relevant capital structure for comparison purposes is at the operating company level not the holding company, as used by Dr. Woolridge. The Commission in this case will be setting the capital structure for UNS Electric, the operating company, which will be used to finance investments in rate base that provides electric utility service to customers. As shown in Exhibit JRW-4, Dr. Woolridge's comparison of UNS Electric's common equity ratio to the median for the proxy group companies is performed using data from AUS Utilities, which are reported at the holding company level rather than the operating company level. As such, Dr. Woolridge's analysis

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97 *Ibid.*, Appendix C, at C-1.

98 Direct Testimony of Robert B. Mease, at 30.

includes corporate-level debt that is not part of the regulated or financial capital structure of the operating utilities.

As discussed in my Direct Testimony, UNS Electric's proposed common equity ratio of 52.83 percent is below the mean common equity ratio of the operating companies in my proxy group of 53.72 percent.[99] The Company's proposed capital structure is consistent with the actual percentage of equity and debt that UNS Electric has used to finance its rate base, consistent with the range of equity ratios at the operating company level for the electric utility companies in my proxy group, and consistent with the requirements to maintain the Company's current credit rating. For those reasons, I continue to support UNS Electric's proposed capital structure as reasonable.

VII. RESPONSE TO WAL-MART WITNESS CHRISS

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

A. Mr. Chriss does not recommend a specific ROE. Rather, he observes that the Company's proposed 10.35 percent recommendation exceeds recently authorized ROEs across the country which, according to Mr. Chriss, have averaged 9.85 percent for all electric utilities from 2012 through 2015, and 9.98 percent for vertically-integrated electric utilities.[100] Mr. Chriss also testifies that the industry trend has been toward declining ROEs for electric utilities over this time period.[101] Mr. Chriss concludes that the Commission should approve an ROE no higher than the currently allowed ROE of 9.50 percent unless the Commission "determines that UNSE has sufficiently and substantially demonstrated a significant change in the economic environment faced by the Company"[102] since the Commission's decision in the 2012 rate case.

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99 Direct Testimony of Ann E. Bulkley, at 50.
100 *See* Direct Testimony of Steve W. Chriss, at 8.
101 *Ibid.*, at 9.
102 *Ibid.*

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

A. With respect to Mr. Chriss' observation that the recommended ROE of 10.35 percent is higher than returns authorized for electric utilities by other regulatory commissions, my response is that those returns were set during a period when interest rates were generally declining. Furthermore, UNS Electric's business and regulatory risk is above average, which supports an authorized ROE above the proxy group average. Mr. Chriss recommends an allowed ROE of no more than 9.50 percent for UNS Electric, which is almost 50 basis points below the average ROE of 9.98 percent for vertically integrated electric utilities in recent years. Further, if the Commission finds recently authorized ROEs to be a useful benchmark in this proceeding, my recommended ROE and range of 10.00 percent to 10.60 percent is within the range of ROEs authorized for electric utilities from 2012-2015 on a nationwide basis, while Mr. Mease's and Dr. Woolridge's recommended ROEs of 8.35 percent and 8.75 percent, respectively, are well below the lowest of all such authorizations, as shown in Chart 1

Lastly, both my Direct and Rebuttal Testimony explain how current economic and forward-looking capital market conditions are different than those at the time of the Commission's decision in the 2012 rate case for UNS Electric. In particular, in Section III of my Rebuttal Testimony, I discuss how wider credit spreads and investor expectations for higher interest rates provide support for the conclusion that the Cost of Equity is higher now than in December 2013 and will continue increasing from current levels.

VIII. UPDATED ANALYSES AND RECOMMENDATION

Q. Have you updated your ROE analyses?

A. Yes. I have updated the Constant Growth and Multi-Stage DCF analyses, the CAPM analysis, and the Bond Yield Plus Risk Premium analysis based on market data through November 30, 2015. The results of my updated analyses are shown in Table 6.

Table 6: Summary of Analytical Results

	Mean Low	Mean	Mean High
Constant Growth DCF			
30-Day Average	8.41%	9.35%	10.32%
90-Day Average	8.50%	9.44%	10.42%
180-Day Average	8.52%	9.46%	10.43%
Multi-Stage DCF			
30-Day Average	9.29%	9.52%	9.78%
90-Day Average	9.39%	9.63%	9.89%
180-Day Average	9.40%	9.64%	9.91%
CAPM			
	Current Risk Free Rate (2.98%)	**2015-2017 Projected Risk Free Rate (3.37%)**	**2017-2021 Projected Risk Free Rate (4.80%)**
Bloomberg	9.67%	9.81%	10.34%
Value Line	11.21%	11.30%	11.61%
Bond Yield Plus Risk Premium			
	Low	**Mean**	**High**
Risk Premium	9.87%	10.04%	10.67%

Q. Please summarize your analytical results and conclusions.

A. Based on the results of my updated analyses, I continue to recommend an ROE range between 10.00 percent and 10.60 percent, with a point estimate of 10.35 percent. My ROE recommendation is supported by mean high results of my Constant Growth DCF

analysis,, and by the mean results of my CAPM analyses. In my view, 10.35 percent is a reasonable ROE estimate for UNS Electric, particularly in light of the Company's higher than average business and regulatory risks.

Q. What is your recommendation for the FVROR for UNS Electric?

A. I continue to recommend a FVROR of 6.22 percent, based on the analysis presented in my Direct Testimony. The methodology used in my Direct Testimony is consistent with the approach that Staff has recommended, updated for current inflation rates. However, I understand that UNS Electric would not oppose Staff's recommendations related to the ROE and fair value increment rate underlying the FVROR as long as the overall revenue increase and rate design approved provides UNS Electric a reasonable opportunity to earn its authorized ROE.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

Exhibit AEB-R-1

30-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	$50.97	3.96%	4.08%	6.50%	5.50%	5.00%	5.67%	9.06%	9.74%	10.59%
American Electric Power Company, Inc.	AEP	$2.24	$56.45	3.97%	4.06%	5.00%	4.68%	4.80%	4.83%	8.74%	8.89%	9.07%
Empire District Electric Company	EDE	$1.04	$22.76	4.57%	4.67%	3.00%	5.00%	5.00%	4.33%	7.64%	9.00%	9.68%
Eversource Energy	ES	$1.67	$51.00	3.27%	3.39%	8.50%	6.57%	6.80%	7.29%	9.95%	10.68%	11.91%
Great Plains Energy Inc.	GXP	$1.05	$27.21	3.86%	3.96%	5.00%	5.23%	6.00%	5.41%	8.95%	9.37%	9.97%
IDACORP, Inc.	IDA	$2.04	$67.21	3.04%	3.08%	1.00%	4.00%	4.00%	3.00%	4.05%	6.08%	7.10%
Otter Tail Corporation	OTTR	$1.23	$26.97	4.56%	4.73%	9.00%	6.00%	NA	7.50%	10.70%	12.23%	13.77%
Pinnacle West Capital Corporation	PNW	$2.50	$63.72	3.92%	4.02%	4.00%	5.15%	5.00%	4.72%	8.00%	8.73%	9.17%
PNM Resources, Inc.	PNM	$0.80	$28.29	2.83%	2.96%	9.00%	10.30%	8.10%	9.13%	11.04%	12.09%	13.27%
Portland General Electric Company	POR	$1.20	$36.90	3.25%	3.33%	6.00%	3.92%	4.10%	4.67%	7.24%	8.00%	9.35%
Westar Energy, Inc.	WR	$1.44	$40.87	3.52%	3.60%	6.00%	3.50%	3.60%	4.37%	7.09%	7.97%	9.63%
MEAN				**3.71%**	**3.81%**	**5.73%**	**5.44%**	**5.24%**	**5.54%**	**8.41%**	**9.35%**	**10.32%**

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of November 30, 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	$49.89	4.05%	4.16%	6.50%	5.50%	5.00%	5.67%	9.15%	9.83%	10.68%
American Electric Power Company, Inc.	AEP	$2.24	$56.09	3.99%	4.09%	5.00%	4.68%	4.80%	4.83%	8.77%	8.92%	9.09%
Empire District Electric Company	EDE	$1.04	$22.43	4.64%	4.74%	3.00%	5.00%	5.00%	4.33%	7.71%	9.07%	9.75%
Eversource Energy	ES	$1.67	$49.67	3.36%	3.48%	8.50%	6.57%	6.80%	7.29%	10.04%	10.77%	12.01%
Great Plains Energy Inc.	GXP	$1.05	$26.43	3.97%	4.08%	5.00%	5.23%	6.00%	5.41%	9.07%	9.49%	10.09%
IDACORP, Inc.	IDA	$2.04	$63.77	3.20%	3.25%	1.00%	4.00%	4.00%	3.00%	4.21%	6.25%	7.26%
Otter Tail Corporation	OTTR	$1.23	$26.61	4.62%	4.80%	9.00%	6.00%	NA	7.50%	10.76%	12.30%	13.83%
Pinnacle West Capital Corporation	PNW	$2.50	$62.62	3.99%	4.09%	4.00%	5.15%	5.00%	4.72%	8.07%	8.80%	9.25%
PNM Resources, Inc.	PNM	$0.80	$27.17	2.94%	3.08%	9.00%	10.30%	8.10%	9.13%	11.16%	12.21%	13.40%
Portland General Electric Company	POR	$1.20	$36.26	3.31%	3.39%	6.00%	3.92%	4.10%	4.67%	7.29%	8.06%	9.41%
Westar Energy, Inc.	WR	$1.44	$38.70	3.72%	3.80%	6.00%	3.50%	3.60%	4.37%	7.29%	8.17%	9.83%
MEAN				**3.80%**	**3.90%**	**5.73%**	**5.44%**	**5.24%**	**5.54%**	**8.50%**	**9.44%**	**10.42%**

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-day average as of November 30, 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	$49.81	4.06%	4.17%	6.50%	5.50%	5.00%	5.67%	9.16%	9.84%	10.69%
American Electric Power Company, Inc.	AEP	$2.24	$55.79	4.01%	4.11%	5.00%	4.68%	4.80%	4.83%	8.79%	8.94%	9.12%
Empire District Electric Company	EDE	$1.04	$22.95	4.53%	4.63%	3.00%	5.00%	5.00%	4.33%	7.60%	8.96%	9.65%
Eversource Energy	ES	$1.67	$49.08	3.40%	3.53%	8.50%	6.57%	6.80%	7.29%	10.08%	10.82%	12.05%
Great Plains Energy Inc.	GXP	$1.05	$26.12	4.02%	4.13%	5.00%	5.23%	6.00%	5.41%	9.12%	9.54%	10.14%
IDACORP, Inc.	IDA	$2.04	$61.69	3.31%	3.36%	1.00%	4.00%	4.00%	3.00%	4.32%	6.36%	7.37%
Otter Tail Corporation	OTTR	$1.23	$27.71	4.44%	4.60%	9.00%	6.00%	NA	7.50%	10.57%	12.10%	13.64%
Pinnacle West Capital Corporation	PNW	$2.50	$61.63	4.06%	4.15%	4.00%	5.15%	5.00%	4.72%	8.14%	8.87%	9.31%
PNM Resources, Inc.	PNM	$0.80	$26.97	2.97%	3.10%	9.00%	10.30%	8.10%	9.13%	11.19%	12.24%	13.42%
Portland General Electric Company	POR	$1.20	$35.68	3.36%	3.44%	6.00%	3.92%	4.10%	4.67%	7.35%	8.11%	9.46%
Westar Energy, Inc.	WR	$1.44	$37.69	3.82%	3.90%	6.00%	3.50%	3.60%	4.37%	7.39%	8.27%	9.94%
MEAN				**3.82%**	**3.92%**	**5.73%**	**5.44%**	**5.24%**	**5.54%**	**8.52%**	**9.46%**	**10.43%**

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-day average as of November 30, 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-R-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	$50.97	$2.02	5.67%	5.62%	5.58%	5.53%	5.49%	5.45%	5.40%	9.84%
American Electric Power Company, Inc.	AEP	$56.45	$2.24	4.83%	4.92%	5.02%	5.11%	5.21%	5.31%	5.40%	9.62%
Empire District Electric Company	EDE	$22.76	$1.04	4.33%	4.51%	4.69%	4.87%	5.05%	5.22%	5.40%	10.13%
Eversource Energy	ES	$51.00	$1.67	7.29%	6.98%	6.66%	6.35%	6.03%	5.72%	5.40%	9.46%
Great Plains Energy Inc.	GXP	$27.21	$1.05	5.41%	5.41%	5.41%	5.41%	5.40%	5.40%	5.40%	9.65%
IDACORP, Inc.	IDA	$67.21	$2.04	3.00%	3.40%	3.80%	4.20%	4.60%	5.00%	5.40%	8.23%
Otter Tail Corporation	OTTR	$26.97	$1.23	7.50%	7.15%	6.80%	6.45%	6.10%	5.75%	5.40%	11.14%
Pinnacle West Capital Corporation	PNW	$63.72	$2.50	4.72%	4.83%	4.94%	5.06%	5.17%	5.29%	5.40%	9.54%
PNM Resources, Inc.	PNM	$28.29	$0.80	9.13%	8.51%	7.89%	7.27%	6.65%	6.02%	5.40%	9.33%
Portland General Electric Company	POR	$36.90	$1.20	4.67%	4.79%	4.92%	5.04%	5.16%	5.28%	5.40%	8.80%
Westar Energy, Inc.	WR	$40.87	$1.44	4.37%	4.54%	4.71%	4.88%	5.06%	5.23%	5.40%	9.02%
MEAN											**9.52%**

Notes:
[1] Source: Bloomberg Professional, equals 30-trading day average as of November 30, 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	$49.89	$2.02	5.67%	5.62%	5.58%	5.53%	5.49%	5.45%	5.40%	9.94%
American Electric Power Company, Inc.	AEP	$56.09	$2.24	4.83%	4.92%	5.02%	5.11%	5.21%	5.31%	5.40%	9.65%
Empire District Electric Company	EDE	$22.43	$1.04	4.33%	4.51%	4.69%	4.87%	5.05%	5.22%	5.40%	10.20%
Eversource Energy	ES	$49.67	$1.67	7.29%	6.98%	6.66%	6.35%	6.03%	5.72%	5.40%	9.57%
Great Plains Energy Inc.	GXP	$26.43	$1.05	5.41%	5.41%	5.41%	5.41%	5.40%	5.40%	5.40%	9.78%
IDACORP, Inc.	IDA	$63.77	$2.04	3.00%	3.40%	3.80%	4.20%	4.60%	5.00%	5.40%	8.39%
Otter Tail Corporation	OTTR	$26.61	$1.23	7.50%	7.15%	6.80%	6.45%	6.10%	5.75%	5.40%	11.22%
Pinnacle West Capital Corporation	PNW	$62.62	$2.50	4.72%	4.83%	4.94%	5.06%	5.17%	5.29%	5.40%	9.61%
PNM Resources, Inc.	PNM	$27.17	$0.80	9.13%	8.51%	7.89%	7.27%	6.65%	6.02%	5.40%	9.49%
Portland General Electric Company	POR	$36.26	$1.20	4.67%	4.79%	4.92%	5.04%	5.16%	5.28%	5.40%	8.86%
Westar Energy, Inc.	WR	$38.70	$1.44	4.37%	4.54%	4.71%	4.88%	5.06%	5.23%	5.40%	9.23%
MEAN											**9.63%**

Notes:
[1] Source: Bloomberg Professional, equals 90-trading day average as of November 30, 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	$49.81	$2.02	5.67%	5.62%	5.58%	5.53%	5.49%	5.45%	5.40%	9.95%
American Electric Power Company, Inc.	AEP	$55.79	$2.24	4.83%	4.92%	5.02%	5.11%	5.21%	5.31%	5.40%	9.67%
Empire District Electric Company	EDE	$22.95	$1.04	4.33%	4.51%	4.69%	4.87%	5.05%	5.22%	5.40%	10.09%
Eversource Energy	ES	$49.08	$1.67	7.29%	6.98%	6.66%	6.35%	6.03%	5.72%	5.40%	9.62%
Great Plains Energy Inc.	GXP	$26.12	$1.05	5.41%	5.41%	5.41%	5.41%	5.40%	5.40%	5.40%	9.84%
IDACORP, Inc.	IDA	$61.69	$2.04	3.00%	3.40%	3.80%	4.20%	4.60%	5.00%	5.40%	8.49%
Otter Tail Corporation	OTTR	$27.71	$1.23	7.50%	7.15%	6.80%	6.45%	6.10%	5.75%	5.40%	10.98%
Pinnacle West Capital Corporation	PNW	$61.63	$2.50	4.72%	4.83%	4.94%	5.06%	5.17%	5.29%	5.40%	9.68%
PNM Resources, Inc.	PNM	$26.97	$0.80	9.13%	8.51%	7.89%	7.27%	6.65%	6.02%	5.40%	9.52%
Portland General Electric Company	POR	$35.68	$1.20	4.67%	4.79%	4.92%	5.04%	5.16%	5.28%	5.40%	8.92%
Westar Energy, Inc.	WR	$37.69	$1.44	4.37%	4.54%	4.71%	4.88%	5.06%	5.23%	5.40%	9.34%
MEAN											**9.64%**

Notes:
[1] Source: Bloomberg Professional, equals 180-trading day average as of November 30, 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	$50.97	$2.02	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	9.66%
American Electric Power Company, Inc.	AEP	$56.45	$2.24	4.68%	4.80%	4.92%	5.04%	5.16%	5.28%	5.40%	9.58%
Empire District Electric Company	EDE	$22.76	$1.04	3.00%	3.40%	3.80%	4.20%	4.60%	5.00%	5.40%	9.74%
Eversource Energy	ES	$51.00	$1.67	6.57%	6.38%	6.18%	5.99%	5.79%	5.60%	5.40%	9.28%
Great Plains Energy Inc.	GXP	$27.21	$1.05	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	9.54%
IDACORP, Inc.	IDA	$67.21	$2.04	1.00%	1.73%	2.47%	3.20%	3.93%	4.67%	5.40%	7.85%
Otter Tail Corporation	OTTR	$26.97	$1.23	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	10.64%
Pinnacle West Capital Corporation	PNW	$63.72	$2.50	4.00%	4.23%	4.47%	4.70%	4.93%	5.17%	5.40%	9.35%
PNM Resources, Inc.	PNM	$28.29	$0.80	8.10%	7.65%	7.20%	6.75%	6.30%	5.85%	5.40%	9.08%
Portland General Electric Company	POR	$36.90	$1.20	3.92%	4.17%	4.41%	4.66%	4.91%	5.15%	5.40%	8.63%
Westar Energy, Inc.	WR	$40.87	$1.44	3.50%	3.82%	4.13%	4.45%	4.77%	5.08%	5.40%	8.82%
MEAN											**9.29%**

Notes:
[1] Source: Bloomberg Professional, equals 30-trading day average as of November 30, 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	$49.89	$2.02	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	9.75%
American Electric Power Company, Inc.	AEP	$56.09	$2.24	4.68%	4.80%	4.92%	5.04%	5.16%	5.28%	5.40%	9.61%
Empire District Electric Company	EDE	$22.43	$1.04	3.00%	3.40%	3.80%	4.20%	4.60%	5.00%	5.40%	9.80%
Eversource Energy	ES	$49.67	$1.67	6.57%	6.38%	6.18%	5.99%	5.79%	5.60%	5.40%	9.38%
Great Plains Energy Inc.	GXP	$26.43	$1.05	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	9.67%
IDACORP, Inc.	IDA	$63.77	$2.04	1.00%	1.73%	2.47%	3.20%	3.93%	4.67%	5.40%	7.99%
Otter Tail Corporation	OTTR	$26.61	$1.23	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	10.71%
Pinnacle West Capital Corporation	PNW	$62.62	$2.50	4.00%	4.23%	4.47%	4.70%	4.93%	5.17%	5.40%	9.42%
PNM Resources, Inc.	PNM	$27.17	$0.80	8.10%	7.65%	7.20%	6.75%	6.30%	5.85%	5.40%	9.23%
Portland General Electric Company	POR	$36.26	$1.20	3.92%	4.17%	4.41%	4.66%	4.91%	5.15%	5.40%	8.69%
Westar Energy, Inc.	WR	$38.70	$1.44	3.50%	3.82%	4.13%	4.45%	4.77%	5.08%	5.40%	9.02%
MEAN											**9.39%**

Notes:
[1] Source: Bloomberg Professional, equals 90-trading day average as of November 30, 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	$49.81	$2.02	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	9.76%
American Electric Power Company, Inc.	AEP	$55.79	$2.24	4.68%	4.80%	4.92%	5.04%	5.16%	5.28%	5.40%	9.63%
Empire District Electric Company	EDE	$22.95	$1.04	3.00%	3.40%	3.80%	4.20%	4.60%	5.00%	5.40%	9.70%
Eversource Energy	ES	$49.08	$1.67	6.57%	6.38%	6.18%	5.99%	5.79%	5.60%	5.40%	9.43%
Great Plains Energy Inc.	GXP	$26.12	$1.05	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	9.72%
IDACORP, Inc.	IDA	$61.69	$2.04	1.00%	1.73%	2.47%	3.20%	3.93%	4.67%	5.40%	8.09%
Otter Tail Corporation	OTTR	$27.71	$1.23	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	10.49%
Pinnacle West Capital Corporation	PNW	$61.63	$2.50	4.00%	4.23%	4.47%	4.70%	4.93%	5.17%	5.40%	9.49%
PNM Resources, Inc.	PNM	$26.97	$0.80	8.10%	7.65%	7.20%	6.75%	6.30%	5.85%	5.40%	9.26%
Portland General Electric Company	POR	$35.68	$1.20	3.92%	4.17%	4.41%	4.66%	4.91%	5.15%	5.40%	8.75%
Westar Energy, Inc.	WR	$37.69	$1.44	3.50%	3.82%	4.13%	4.45%	4.77%	5.08%	5.40%	9.12%
MEAN											**9.40%**

Notes:
[1] Source: Bloomberg Professional, equals 180-trading day average as of November 30, 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	$50.97	$2.02	6.50%	6.32%	6.13%	5.95%	5.77%	5.58%	5.40%	10.08%
American Electric Power Company, Inc.	AEP	$56.45	$2.24	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	9.67%
Empire District Electric Company	EDE	$22.76	$1.04	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	10.33%
Eversource Energy	ES	$51.00	$1.67	8.50%	7.98%	7.47%	6.95%	6.43%	5.92%	5.40%	9.77%
Great Plains Energy Inc.	GXP	$27.21	$1.05	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	9.82%
IDACORP, Inc.	IDA	$67.21	$2.04	4.00%	4.23%	4.47%	4.70%	4.93%	5.17%	5.40%	8.43%
Otter Tail Corporation	OTTR	$26.97	$1.23	9.00%	8.40%	7.80%	7.20%	6.60%	6.00%	5.40%	11.67%
Pinnacle West Capital Corporation	PNW	$63.72	$2.50	5.15%	5.19%	5.23%	5.28%	5.32%	5.36%	5.40%	9.66%
PNM Resources, Inc.	PNM	$28.29	$0.80	10.30%	9.48%	8.67%	7.85%	7.03%	6.22%	5.40%	9.62%
Portland General Electric Company	POR	$36.90	$1.20	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	9.11%
Westar Energy, Inc.	WR	$40.87	$1.44	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	9.43%
MEAN											**9.78%**

Notes:
[1] Source: Bloomberg Professional, equals 30-trading day average as of November 30, 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	$49.89	$2.02	6.50%	6.32%	6.13%	5.95%	5.77%	5.58%	5.40%	10.19%
American Electric Power Company, Inc.	AEP	$56.09	$2.24	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	9.69%
Empire District Electric Company	EDE	$22.43	$1.04	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	10.40%
Eversource Energy	ES	$49.67	$1.67	8.50%	7.98%	7.47%	6.95%	6.43%	5.92%	5.40%	9.89%
Great Plains Energy Inc.	GXP	$26.43	$1.05	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	9.95%
IDACORP, Inc.	IDA	$63.77	$2.04	4.00%	4.23%	4.47%	4.70%	4.93%	5.17%	5.40%	8.60%
Otter Tail Corporation	OTTR	$26.61	$1.23	9.00%	8.40%	7.80%	7.20%	6.60%	6.00%	5.40%	11.75%
Pinnacle West Capital Corporation	PNW	$62.62	$2.50	5.15%	5.19%	5.23%	5.28%	5.32%	5.36%	5.40%	9.73%
PNM Resources, Inc.	PNM	$27.17	$0.80	10.30%	9.48%	8.67%	7.85%	7.03%	6.22%	5.40%	9.79%
Portland General Electric Company	POR	$36.26	$1.20	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	9.18%
Westar Energy, Inc.	WR	$38.70	$1.44	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	9.66%
MEAN											**9.89%**

Notes:
[1] Source: Bloomberg Professional, equals 90-trading day average as of November 30, 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	$49.81	$2.02	6.50%	6.32%	6.13%	5.95%	5.77%	5.58%	5.40%	10.19%
American Electric Power Company, Inc.	AEP	$55.79	$2.24	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	9.72%
Empire District Electric Company	EDE	$22.95	$1.04	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	10.29%
Eversource Energy	ES	$49.08	$1.67	8.50%	7.98%	7.47%	6.95%	6.43%	5.92%	5.40%	9.94%
Great Plains Energy Inc.	GXP	$26.12	$1.05	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	10.00%
IDACORP, Inc.	IDA	$61.69	$2.04	4.00%	4.23%	4.47%	4.70%	4.93%	5.17%	5.40%	8.71%
Otter Tail Corporation	OTTR	$27.71	$1.23	9.00%	8.40%	7.80%	7.20%	6.60%	6.00%	5.40%	11.50%
Pinnacle West Capital Corporation	PNW	$61.63	$2.50	5.15%	5.19%	5.23%	5.28%	5.32%	5.36%	5.40%	9.80%
PNM Resources, Inc.	PNM	$26.97	$0.80	10.30%	9.48%	8.67%	7.85%	7.03%	6.22%	5.40%	9.82%
Portland General Electric Company	POR	$35.68	$1.20	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	9.24%
Westar Energy, Inc.	WR	$37.69	$1.44	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	9.77%
MEAN											**9.91%**

Notes:
[1] Source: Bloomberg Professional, equals 180-trading day average as of November 30, 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-R-3

CALCULATION OF LONG-TERM GDP GROWTH RATE

Step 1	
Real GDP ($ Billions) [1]	
1929	$ 1,056.6
2014	$ 15,961.7
Compound Annual Growth Rate	**3.25%**
Step 2	
Consumer Price Index (YoY % Change) [2]	
2022-2026	2.30%
Average	2.30%
Consumer Price Index (All-Urban) [3]	
2025	2.89
2040	3.95
Compound Annual Growth Rate	2.11%
GDP Chain-type Price Index (2009=1.000) [3]	
2025	1.31
2040	1.73
Compound Annual Growth Rate	1.85%
Average Inflation Forecast	**2.09%**
Long-Term GDP Growth Rate	**5.40%**

Notes:

[1] Bureau of Economic Analysis, November 24, 2015
[2] Blue Chip Financial Forecasts, Vol. 34, No. 6, June 1, 2015, at 14
[3] Energy Information Administration, Annual Energy Outlook 2015, Table 20

Exhibit AEB-R-4

BETA
AS OF NOVEMBER 30, 2015

		[1]	[2]
		Bloomberg	Value Line
ALLETE, Inc.	ALE	0.602	0.800
American Electric Power Company, Inc.	AEP	0.569	0.700
Empire District Electric Company	EDE	0.566	0.700
Eversource Energy	ES	0.559	0.750
Great Plains Energy Inc.	GXP	0.622	0.850
IDACORP, Inc.	IDA	0.710	0.800
Otter Tail Corporation	OTTR	0.759	0.850
Pinnacle West Capital Corporation	PNW	0.626	0.750
PNM Resources, Inc.	PNM	0.662	0.850
Portland General Electric Company	POR	0.683	0.800
Westar Energy, Inc.	WR	0.636	0.750
Mean		0.636	0.782

Notes:
[1] Source: Bloomberg Professional
[2] Source: Value Line; dated Sep. 18, 2015, Oct. 30, 2015, and Nov. 20, 2015.

Exhibit AEB-R-5

CAPITAL ASSET PRICING MODEL

	[4] Risk-Free Rate	[5] Average Beta	[6] Market Risk Premium	[7] ROE
Proxy Group Average Bloomberg Beta				
[1] Current 30-day average of 30-year U.S. Treasury bond yield	2.98%	0.636	10.53%	9.67%
[2] Near-term projected 30-year U.S. Treasury bond yield (Q4 2015 - Q1 2017)	3.37%	0.636	10.14%	9.81%
[3] Projected 30-year U.S. Treasury bond yield (2017 - 2021)	4.80%	0.636	8.71%	10.34%
			Mean:	9.94%
Proxy Group Average Value Line Beta				
[1] Current 30-day average of 30-year U.S. Treasury bond yield	2.98%	0.782	10.53%	11.21%
[2] Near-term projected 30-year U.S. Treasury bond yield (Q4 2015 - Q1 2017)	3.37%	0.782	10.14%	11.30%
[3] Projected 30-year U.S. Treasury bond yield (2017 - 2021)	4.80%	0.782	8.71%	11.61%
			Mean:	11.37%

[1] Source: Bloomberg Professional
[2] Source: Blue Chip Financial Forecasts, Vol. 34, No. 11, November 1, 2015, at 2
[3] Source: Blue Chip Financial Forecasts, Vol. 34, No. 6, June 1, 2015, 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	2.13%		
[9] Estimated Weighted Average Long-Term Growth Rate	11.26%		
[10] S&P 500 Estimated Required Market Return	13.51%		
[11] Risk-Free Rate	2.98%	3.37%	4.80%
[12] Implied Market Risk Premium	10.53%	10.14%	8.71%

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	0.06%	1.28%	0.00%	9.77%	0.01%
LyondellBasell Industries NV	LYB	0.23%	3.26%	0.01%	5.86%	0.01%
American Express Co	AXP	0.37%	1.62%	0.01%	10.00%	0.04%
Verizon Communications Inc	VZ	0.98%	4.97%	0.05%	7.55%	0.07%
Avago Technologies Ltd	AVGO	0.19%	1.29%	0.00%	20.11%	0.04%
Boeing Co/The	BA	0.52%	2.50%	0.01%	12.42%	0.06%
Caterpillar Inc	CAT	0.22%	4.24%	0.01%	9.00%	0.02%
JPMorgan Chase & Co	JPM	1.30%	2.64%	0.03%	7.82%	0.10%
Chevron Corp	CVX	0.91%	4.69%	0.04%	-3.57%	-0.03%
Coca-Cola Co/The	KO	0.98%	3.10%	0.03%	5.79%	0.06%
AbbVie Inc	ABBV	0.50%	3.92%	0.02%	8.64%	0.04%
Walt Disney Co/The	DIS	0.99%	1.16%	0.01%	11.58%	0.11%
El du Pont de Nemours & Co	DD	0.31%	2.26%	0.01%	5.20%	0.02%
Exxon Mobil Corp	XOM	1.80%	3.58%	0.06%	-0.35%	-0.01%
Phillips 66	PSX	0.26%	2.45%	0.01%	5.39%	0.01%
General Electric Co	GE	1.50%	3.07%	0.05%	7.86%	0.12%
HP Inc	HPQ	0.12%	3.96%	0.00%	4.53%	0.01%
Home Depot Inc/The	HD	0.90%	1.76%	0.02%	14.06%	0.13%
International Business Machines Corp	IBM	0.72%	3.73%	0.03%	6.48%	0.05%
Johnson & Johnson	JNJ	1.48%	2.96%	0.04%	5.91%	0.09%
McDonald's Corp	MCD	0.55%	3.12%	0.02%	8.62%	0.05%
Merck & Co Inc	MRK	0.78%	3.47%	0.03%	6.70%	0.05%
3M Co	MMM	0.51%	2.62%	0.01%	9.05%	0.05%
Bank of America Corp	BAC	0.96%	1.15%	0.01%	24.88%	0.24%
CSRA Inc	CSRA	0.02%	n/a	n/a	n/a	n/a
Pfizer Inc	PFE	1.07%	3.42%	0.04%	4.66%	0.05%
Procter & Gamble Co/The	PG	1.08%	3.54%	0.04%	7.11%	0.08%
AT&T Inc	T	1.10%	5.58%	0.06%	4.42%	0.05%
Travelers Cos Inc/The	TRV	0.18%	2.13%	0.00%	7.81%	0.01%
United Technologies Corp	UTX	0.45%	2.67%	0.01%	8.30%	0.04%
Analog Devices Inc	ADI	0.10%	2.60%	0.00%	10.45%	0.01%
Wal-Mart Stores Inc	WMT	1.00%	3.33%	0.03%	0.59%	0.01%
Cisco Systems Inc	CSCO	0.73%	3.08%	0.02%	7.86%	0.06%
Intel Corp	INTC	0.87%	2.76%	0.02%	8.60%	0.07%
General Motors Co	GM	0.30%	3.98%	0.01%	11.69%	0.03%
Microsoft Corp	MSFT	2.30%	2.65%	0.06%	9.93%	0.23%
Dollar General Corp	DG	0.10%	1.35%	0.00%	12.29%	0.01%
Kinder Morgan Inc/DE	KMI	0.28%	8.66%	0.02%	6.13%	0.02%
Citigroup Inc	C	0.85%	0.37%	0.00%	25.41%	0.22%
American International Group Inc	AIG	0.42%	1.76%	0.01%	9.04%	0.04%
Honeywell International Inc	HON	0.42%	2.29%	0.01%	9.69%	0.04%
Altria Group Inc	MO	0.60%	3.92%	0.02%	7.78%	0.05%
HCA Holdings Inc	HCA	0.15%	n/a	n/a	10.63%	0.02%
Under Armour Inc	UA	0.08%	n/a	n/a	23.43%	0.02%
International Paper Co	IP	0.09%	4.21%	0.00%	8.56%	0.01%
Hewlett Packard Enterprise Co	HPE	0.14%	1.48%	0.00%	4.09%	0.01%
Abbott Laboratories	ABT	0.35%	2.14%	0.01%	11.95%	0.04%
Aflac Inc	AFL	0.15%	2.51%	0.00%	8.53%	0.01%
Air Products & Chemicals Inc	APD	0.16%	2.37%	0.00%	5.00%	0.01%
Airgas Inc	ARG	0.05%	1.74%	0.00%	7.47%	0.00%
Royal Caribbean Cruises Ltd	RCL	0.11%	1.62%	0.00%	19.70%	0.02%
American Electric Power Co Inc	AEP	0.15%	4.00%	0.01%	5.27%	0.01%
Hess Corp	HES	0.09%	1.69%	0.00%	-26.25%	-0.02%
Anadarko Petroleum Corp	APC	0.16%	1.80%	0.00%	8.33%	0.01%
Aon PLC	AON	0.14%	1.27%	0.00%	11.68%	0.02%
Apache Corp	APA	0.10%	2.03%	0.00%	-1.92%	0.00%
Archer-Daniels-Midland Co	ADM	0.12%	3.07%	0.00%	2.70%	0.00%
AGL Resources Inc	GAS	0.04%	3.26%	0.00%	6.00%	0.00%
Automatic Data Processing Inc	ADP	0.21%	2.46%	0.01%	10.33%	0.02%
Verisk Analytics Inc	VRSK	0.07%	n/a	n/a	12.00%	0.01%
AutoZone Inc	AZO	0.13%	n/a	n/a	12.40%	0.02%
Avery Dennison Corp	AVY	0.03%	2.24%	0.00%	9.05%	0.00%
Baker Hughes Inc	BHI	0.12%	1.26%	0.00%	8.00%	0.01%
Ball Corp	BLL	0.05%	0.75%	0.00%	6.05%	0.00%
Bank of New York Mellon Corp/The	BK	0.25%	1.55%	0.00%	12.57%	0.03%
CR Bard Inc	BCR	0.07%	0.51%	0.00%	13.78%	0.01%
Baxter International Inc	BAX	0.11%	1.22%	0.00%	8.75%	0.01%
Becton Dickinson and Co	BDX	0.17%	1.76%	0.00%	11.42%	0.02%
Berkshire Hathaway Inc	BRK/B	0.89%	n/a	n/a	5.00%	0.04%
Best Buy Co Inc	BBY	0.06%	2.89%	0.00%	10.00%	0.01%
H&R Block Inc	HRB	0.05%	2.18%	0.00%	11.00%	0.01%
Boston Scientific Corp	BSX	0.13%	n/a	n/a	9.12%	0.01%
Bristol-Myers Squibb Co	BMY	0.59%	2.21%	0.01%	13.53%	0.08%
Brown-Forman Corp	BF/B	0.07%	1.33%	0.00%	8.36%	0.01%
Cabot Oil & Gas Corp	COG	0.04%	0.42%	0.00%	48.42%	0.02%
Campbell Soup Co	CPB	0.09%	2.39%	0.00%	5.42%	0.00%
Kansas City Southern	KSU	0.05%	1.45%	0.00%	9.60%	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	0.16%	2.37%	0.00%	19.17%	0.03%
Qorvo Inc	QRVO	0.04%	n/a	n/a	16.21%	0.01%
CenturyLink Inc	CTL	0.08%	8.02%	0.01%	0.19%	0.00%
Chubb Corp/The	CB	0.16%	1.75%	0.00%	9.20%	0.01%
Cigna Corp	CI	0.18%	0.03%	0.00%	11.40%	0.02%
Frontier Communications Corp	FTR	0.03%	8.42%	0.00%	3.00%	0.00%
Clorox Co/The	CLX	0.08%	2.48%	0.00%	6.87%	0.01%
CMS Energy Corp	CMS	0.05%	3.31%	0.00%	6.25%	0.00%
Coca-Cola Enterprises Inc	CCE	0.06%	2.23%	0.00%	6.04%	0.00%
Colgate-Palmolive Co	CL	0.31%	2.31%	0.01%	7.88%	0.02%
Comerica Inc	CMA	0.04%	1.81%	0.00%	9.28%	0.00%
CA Inc	CA	0.07%	3.56%	0.00%	5.50%	0.00%
Computer Sciences Corp	CSC	0.02%	1.79%	0.00%	3.60%	0.00%
ConAgra Foods Inc	CAG	0.09%	2.44%	0.00%	8.50%	0.01%
Consolidated Edison Inc	ED	0.10%	4.18%	0.00%	2.74%	0.00%
SL Green Realty Corp	SLG	0.06%	2.03%	0.00%	4.98%	0.00%
Corning Inc	GLW	0.12%	2.56%	0.00%	5.55%	0.01%
CSX Corp	CSX	0.15%	2.53%	0.00%	8.59%	0.01%
Cummins Inc	CMI	0.09%	3.89%	0.00%	6.90%	0.01%
Danaher Corp	DHR	0.35%	0.56%	0.00%	12.90%	0.05%
Target Corp	TGT	0.24%	3.09%	0.01%	9.82%	0.02%
Deere & Co	DE	0.14%	3.02%	0.00%	5.15%	0.01%
Dominion Resources Inc/VA	D	0.21%	3.84%	0.01%	6.00%	0.01%
Dover Corp	DOV	0.05%	2.55%	0.00%	12.00%	0.01%
Dow Chemical Co/The	DOW	0.32%	3.53%	0.01%	6.53%	0.02%
Duke Energy Corp	DUK	0.25%	4.87%	0.01%	4.10%	0.01%
Eaton Corp PLC	ETN	0.14%	3.78%	0.01%	8.09%	0.01%
Ecolab Inc	ECL	0.19%	1.11%	0.00%	13.22%	0.02%
PerkinElmer Inc	PKI	0.03%	0.53%	0.00%	6.14%	0.00%
EMC Corp/MA	EMC	0.26%	1.82%	0.00%	8.53%	0.02%
Emerson Electric Co	EMR	0.17%	3.80%	0.01%	7.82%	0.01%
EOG Resources Inc	EOG	0.24%	0.80%	0.00%	2.05%	0.00%
Entergy Corp	ETR	0.06%	5.10%	0.00%	1.64%	0.00%
Equifax Inc	EFX	0.07%	1.04%	0.00%	10.00%	0.01%
EQT Corp	EQT	0.05%	0.21%	0.00%	30.00%	0.01%
XL Group PLC	XL	0.06%	2.10%	0.00%	9.50%	0.01%
FedEx Corp	FDX	0.24%	0.63%	0.00%	13.78%	0.03%
Macy's Inc	M	0.07%	3.68%	0.00%	7.88%	0.01%
FMC Corp	FMC	0.03%	1.54%	0.00%	9.00%	0.00%
Ford Motor Co	F	0.30%	4.19%	0.01%	13.79%	0.04%
NextEra Energy Inc	NEE	0.24%	3.08%	0.01%	7.00%	0.02%
Franklin Resources Inc	BEN	0.13%	1.43%	0.00%	7.69%	0.01%
Freeport-McMoRan Inc	FCX	0.05%	2.45%	0.00%	-55.40%	-0.03%
TEGNA Inc	TGNA	0.03%	1.98%	0.00%	4.43%	0.00%
Gap Inc/The	GPS	0.06%	3.44%	0.00%	8.79%	0.01%
General Dynamics Corp	GD	0.25%	1.88%	0.00%	9.02%	0.02%
General Mills Inc	GIS	0.18%	3.05%	0.01%	7.50%	0.01%
Genuine Parts Co	GPC	0.07%	2.71%	0.00%	8.62%	0.01%
WW Grainger Inc	GWW	0.07%	2.33%	0.00%	10.08%	0.01%
Halliburton Co	HAL	0.18%	1.81%	0.00%	6.02%	0.01%
Harley-Davidson Inc	HOG	0.05%	2.53%	0.00%	10.13%	0.01%
Harman International Industries Inc	HAR	0.04%	1.36%	0.00%	16.00%	0.01%
Harris Corp	HRS	0.05%	2.41%	0.00%	n/a	n/a
HCP Inc	HCP	0.09%	6.36%	0.01%	2.78%	0.00%
Helmerich & Payne Inc	HP	0.03%	4.72%	0.00%	1.10%	0.00%
Hershey Co/The	HSY	0.07%	2.70%	0.00%	8.93%	0.01%
Synchrony Financial	SYF	0.14%	n/a	n/a	5.34%	0.01%
Hormel Foods Corp	HRL	0.10%	1.55%	0.00%	8.00%	0.01%
Starwood Hotels & Resorts Worldwide Inc	HOT	0.06%	2.09%	0.00%	8.35%	0.01%
Mondelez International Inc	MDLZ	0.37%	1.56%	0.01%	10.76%	0.04%
CenterPoint Energy Inc	CNP	0.04%	5.84%	0.00%	4.50%	0.00%
Humana Inc	HUM	0.13%	0.69%	0.00%	12.33%	0.02%
Illinois Tool Works Inc	ITW	0.18%	2.34%	0.00%	8.20%	0.01%
Ingersoll-Rand PLC	IR	0.08%	1.98%	0.00%	10.11%	0.01%
Interpublic Group of Cos Inc/The	IPG	0.05%	2.09%	0.00%	6.50%	0.00%
International Flavors & Fragrances Inc	IFF	0.05%	1.87%	0.00%	11.00%	0.01%
Jacobs Engineering Group Inc	JEC	0.03%	n/a	n/a	7.22%	0.00%
Johnson Controls Inc	JCI	0.16%	2.52%	0.00%	10.33%	0.02%
Hanesbrands Inc	HBI	0.06%	1.30%	0.00%	16.30%	0.01%
Kellogg Co	K	0.13%	2.91%	0.00%	4.06%	0.01%
Perrigo Co PLC	PRGO	0.12%	0.33%	0.00%	12.73%	0.01%
Kimberly-Clark Corp	KMB	0.23%	2.95%	0.01%	8.10%	0.02%
Kimco Realty Corp	KIM	0.06%	3.91%	0.00%	4.49%	0.00%
Kohl's Corp	KSS	0.05%	3.82%	0.00%	7.52%	0.00%
Oracle Corp	ORCL	0.88%	1.54%	0.01%	7.72%	0.07%
Kroger Co/The	KR	0.19%	1.12%	0.00%	10.19%	0.02%
Legg Mason Inc	LM	0.03%	1.80%	0.00%	15.95%	0.00%
Leggett & Platt Inc	LEG	0.03%	2.75%	0.00%	n/a	n/a
Lennar Corp	LEN	0.05%	0.31%	0.00%	n/a	n/a
Leucadia National Corp	LUK	0.03%	1.41%	0.00%	n/a	n/a
Eli Lilly & Co	LLY	0.48%	2.44%	0.01%	10.63%	0.05%
L Brands Inc	LB	0.15%	2.10%	0.00%	10.91%	0.02%
Lincoln National Corp	LNC	0.07%	1.82%	0.00%	10.18%	0.01%
Loews Corp	L	0.07%	0.66%	0.00%	n/a	n/a
Lowe's Cos Inc	LOW	0.38%	1.46%	0.01%	16.83%	0.06%
Host Hotels & Resorts Inc	HST	0.07%	4.82%	0.00%	5.00%	0.00%
Marsh & McLennan Cos Inc	MMC	0.15%	2.24%	0.00%	11.99%	0.02%
Masco Corp	MAS	0.05%	1.27%	0.00%	14.79%	0.01%
Mattel Inc	MAT	0.04%	6.11%	0.00%	9.43%	0.00%
McGraw Hill Financial Inc	MHFI	0.14%	1.37%	0.00%	11.17%	0.02%
Medtronic PLC	MDT	0.56%	2.02%	0.01%	8.18%	0.05%

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.
CVS Health Corp	CVS	0.55%	1.49%	0.01%	14.50%	0.08%
Micron Technology Inc	MU	0.09%	n/a	n/a	2.22%	0.00%
Motorola Solutions Inc	MSI	0.07%	2.28%	0.00%	3.00%	0.00%
Murphy Oil Corp	MUR	0.03%	4.90%	0.00%	13.00%	0.00%
Mylan NV	MYL	0.13%	n/a	n/a	9.75%	0.01%
Laboratory Corp of America Holdings	LH	0.07%	n/a	n/a	10.26%	0.01%
Tenet Healthcare Corp	THC	0.02%	n/a	n/a	13.17%	0.00%
Newell Rubbermaid Inc	NWL	0.06%	1.70%	0.00%	9.42%	0.01%
Newmont Mining Corp	NEM	0.05%	0.54%	0.00%	1.43%	0.00%
Twenty-First Century Fox Inc	FOXA	0.18%	1.02%	0.00%	14.92%	0.03%
NIKE Inc	NKE	0.47%	0.97%	0.00%	13.37%	0.06%
NiSource Inc	NI	0.03%	3.23%	0.00%	n/a	n/a
Noble Energy Inc	NBL	0.08%	1.96%	0.00%	1.23%	0.00%
Norfolk Southern Corp	NSC	0.15%	2.48%	0.00%	8.14%	0.01%
Eversource Energy	ES	0.09%	3.28%	0.00%	6.58%	0.01%
Northrop Grumman Corp	NOC	0.18%	1.72%	0.00%	6.57%	0.01%
Wells Fargo & Co	WFC	1.49%	2.72%	0.04%	11.28%	0.17%
Nucor Corp	NUE	0.07%	3.59%	0.00%	10.10%	0.01%
PVH Corp	PVH	0.04%	0.16%	0.00%	9.76%	0.00%
Occidental Petroleum Corp	OXY	0.31%	3.97%	0.01%	8.00%	0.02%
Omnicom Group Inc	OMC	0.09%	2.71%	0.00%	5.33%	0.01%
ONEOK Inc	OKE	0.03%	8.34%	0.00%	8.60%	0.00%
Owens-Illinois Inc	OI	0.02%	n/a	n/a	2.90%	0.00%
PG&E Corp	PCG	0.14%	3.45%	0.00%	3.83%	0.01%
Parker-Hannifin Corp	PH	0.08%	2.41%	0.00%	8.69%	0.01%
PPL Corp	PPL	0.12%	4.44%	0.01%	1.94%	0.00%
PepsiCo Inc	PEP	0.77%	2.81%	0.02%	6.04%	0.05%
Exelon Corp	EXC	0.13%	4.54%	0.01%	5.18%	0.01%
ConocoPhillips	COP	0.35%	5.48%	0.02%	-0.45%	0.00%
PulteGroup Inc	PHM	0.04%	1.64%	0.00%	17.19%	0.01%
Pinnacle West Capital Corp	PNW	0.04%	3.95%	0.00%	5.20%	0.00%
Pitney Bowes Inc	PBI	0.02%	3.47%	0.00%	14.00%	0.00%
Plum Creek Timber Co Inc	PCL	0.05%	3.46%	0.00%	22.82%	0.01%
PNC Financial Services Group Inc/The	PNC	0.26%	2.14%	0.01%	6.99%	0.02%
PPG Industries Inc	PPG	0.15%	1.36%	0.00%	7.03%	0.01%
Praxair Inc	PX	0.17%	2.54%	0.00%	6.85%	0.01%
Precision Castparts Corp	PCP	0.17%	0.05%	0.00%	11.67%	0.02%
Progressive Corp/The	PGR	0.10%	2.23%	0.00%	7.93%	0.01%
Public Service Enterprise Group Inc	PEG	0.10%	3.99%	0.00%	3.94%	0.00%
Raytheon Co	RTN	0.20%	2.16%	0.00%	7.41%	0.01%
Robert Half International Inc	RHI	0.04%	1.56%	0.00%	15.62%	0.01%
Ryder System Inc	R	0.02%	2.49%	0.00%	10.70%	0.00%
SCANA Corp	SCG	0.04%	3.69%	0.00%	6.00%	0.00%
Edison International	EIX	0.10%	2.81%	0.00%	3.42%	0.00%
Schlumberger Ltd	SLB	0.52%	2.59%	0.01%	14.33%	0.07%
Charles Schwab Corp/The	SCHW	0.23%	0.71%	0.00%	20.35%	0.05%
Sherwin-Williams Co/The	SHW	0.14%	0.97%	0.00%	18.05%	0.02%
JM Smucker Co/The	SJM	0.08%	2.21%	0.00%	9.38%	0.01%
Snap-on Inc	SNA	0.05%	1.42%	0.00%	3.30%	0.00%
AMETEK Inc	AME	0.07%	0.64%	0.00%	10.41%	0.01%
Southern Co/The	SO	0.21%	4.87%	0.01%	3.83%	0.01%
BB&T Corp	BBT	0.16%	2.80%	0.00%	11.30%	0.02%
Southwest Airlines Co	LUV	0.16%	0.65%	0.00%	18.09%	0.03%
Southwestern Energy Co	SWN	0.02%	n/a	n/a	9.33%	0.00%
Stanley Black & Decker Inc	SWK	0.09%	2.02%	0.00%	10.67%	0.01%
Public Storage	PSA	0.22%	2.83%	0.01%	4.80%	0.01%
SunTrust Banks Inc	STI	0.12%	2.21%	0.00%	5.86%	0.01%
Sysco Corp	SYY	0.12%	3.02%	0.00%	9.02%	0.01%
TECO Energy Inc	TE	0.03%	3.42%	0.00%	6.00%	0.00%
Tesoro Corp	TSO	0.07%	1.74%	0.00%	16.14%	0.01%
Texas Instruments Inc	TXN	0.31%	2.62%	0.01%	9.48%	0.03%
Textron Inc	TXT	0.06%	0.19%	0.00%	9.26%	0.01%
Thermo Fisher Scientific Inc	TMO	0.29%	0.43%	0.00%	11.60%	0.03%
Tiffany & Co	TIF	0.05%	2.01%	0.00%	10.53%	0.01%
TJX Cos Inc/The	TJX	0.25%	1.19%	0.00%	10.96%	0.03%
Torchmark Corp	TMK	0.04%	0.89%	0.00%	7.19%	0.00%
Total System Services Inc	TSS	0.05%	0.71%	0.00%	11.00%	0.01%
Tyco International Plc	TYC	0.08%	2.32%	0.00%	10.60%	0.01%
Union Pacific Corp	UNP	0.38%	2.62%	0.01%	8.66%	0.03%
UnitedHealth Group Inc	UNH	0.57%	1.77%	0.01%	11.83%	0.07%
Unum Group	UNM	0.05%	2.02%	0.00%	9.00%	0.00%
Marathon Oil Corp	MRO	0.06%	1.14%	0.00%	-3.70%	0.00%
Varian Medical Systems Inc	VAR	0.04%	n/a	n/a	11.37%	0.00%
Ventas Inc	VTR	0.09%	5.47%	0.01%	2.63%	0.00%
VF Corp	VFC	0.15%	2.29%	0.00%	11.53%	0.02%
Vornado Realty Trust	VNO	0.10%	2.60%	0.00%	4.90%	0.00%
ADT Corp/The	ADT	0.03%	2.37%	0.00%	6.47%	0.00%
Vulcan Materials Co	VMC	0.07%	0.39%	0.00%	44.44%	0.03%
Weyerhaeuser Co	WY	0.09%	3.85%	0.00%	3.60%	0.00%
Whirlpool Corp	WHR	0.07%	2.22%	0.00%	16.65%	0.01%
Williams Cos Inc/The	WMB	0.15%	7.00%	0.01%	n/a	n/a
WEC Energy Group Inc	WEC	0.08%	3.71%	0.00%	4.35%	0.00%
Xerox Corp	XRX	0.06%	2.65%	0.00%	8.55%	0.00%
Adobe Systems Inc	ADBE	0.24%	n/a	n/a	18.87%	0.05%
AES Corp/VA	AES	0.04%	4.00%	0.00%	3.71%	0.00%
Amgen Inc	AMGN	0.65%	1.96%	0.01%	8.38%	0.05%
Apple Inc	AAPL	3.49%	1.76%	0.06%	13.50%	0.47%
Autodesk Inc	ADSK	0.08%	n/a	n/a	-1.51%	0.00%
Cintas Corp	CTAS	0.05%	1.15%	0.00%	11.60%	0.01%
Comcast Corp	CMCSA	0.67%	1.64%	0.01%	13.39%	0.09%
Molson Coors Brewing Co	TAP	0.08%	1.78%	0.00%	12.10%	0.01%

STANDARD AND POOR'S 500 INDEX

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KLA-Tencor Corp	KLAC	0.05%	3.13%	0.00%	13.47%	0.01%
Marriott International Inc/MD	MAR	0.10%	1.41%	0.00%	12.67%	0.01%
McCormick & Co Inc/MD	MKC	0.05%	2.00%	0.00%	6.50%	0.00%
Nordstrom Inc	JWN	0.06%	2.63%	0.00%	8.22%	0.00%
PACCAR Inc	PCAR	0.10%	1.85%	0.00%	9.14%	0.01%
Costco Wholesale Corp	COST	0.37%	0.99%	0.00%	9.80%	0.04%
St Jude Medical Inc	STJ	0.09%	1.84%	0.00%	11.25%	0.01%
Stryker Corp	SYK	0.19%	1.43%	0.00%	11.00%	0.02%
Tyson Foods Inc	TSN	0.08%	1.20%	0.00%	8.60%	0.01%
Altera Corp	ALTR	0.08%	1.36%	0.00%	10.45%	0.01%
Applied Materials Inc	AMAT	0.12%	2.13%	0.00%	12.08%	0.01%
Time Warner Inc	TWX	0.30%	2.00%	0.01%	12.37%	0.04%
Bed Bath & Beyond Inc	BBBY	0.05%	n/a	n/a	7.35%	0.00%
American Airlines Group Inc	AAL	0.14%	0.97%	0.00%	18.37%	0.03%
Cardinal Health Inc	CAH	0.15%	1.78%	0.00%	12.36%	0.02%
Celgene Corp	CELG	0.46%	n/a	n/a	24.08%	0.11%
Cerner Corp	CERN	0.11%	n/a	n/a	17.28%	0.02%
Cincinnati Financial Corp	CINF	0.05%	3.01%	0.00%	n/a	n/a
Cablevision Systems Corp	CVC	0.04%	1.97%	0.00%	2.30%	0.00%
DR Horton Inc	DHI	0.06%	0.99%	0.00%	19.20%	0.01%
Flowserve Corp	FLS	0.03%	1.56%	0.00%	7.14%	0.00%
Electronic Arts Inc	EA	0.11%	n/a	n/a	14.33%	0.02%
Express Scripts Holding Co	ESRX	0.31%	n/a	n/a	16.70%	0.05%
Expeditors International of Washington Inc	EXPD	0.05%	1.48%	0.00%	10.06%	0.00%
Fastenal Co	FAST	0.06%	2.76%	0.00%	12.65%	0.01%
M&T Bank Corp	MTB	0.12%	2.23%	0.00%	6.98%	0.01%
Fiserv Inc	FISV	0.12%	n/a	n/a	12.80%	0.01%
Fifth Third Bancorp	FITB	0.09%	2.52%	0.00%	4.58%	0.00%
Gilead Sciences Inc	GILD	0.81%	1.62%	0.01%	11.70%	0.09%
Hasbro Inc	HAS	0.05%	2.52%	0.00%	9.55%	0.00%
Huntington Bancshares Inc/OH	HBAN	0.05%	2.40%	0.00%	8.28%	0.00%
Welltower Inc	HCN	0.12%	5.22%	0.01%	4.49%	0.01%
Biogen Inc	BIIB	0.34%	n/a	n/a	12.00%	0.04%
Linear Technology Corp	LLTC	0.06%	2.62%	0.00%	6.76%	0.00%
Range Resources Corp	RRC	0.03%	0.56%	0.00%	13.48%	0.00%
Northern Trust Corp	NTRS	0.09%	1.92%	0.00%	13.71%	0.01%
Paychex Inc	PAYX	0.10%	3.10%	0.00%	9.39%	0.01%
People's United Financial Inc	PBCT	0.03%	4.00%	0.00%	n/a	n/a
Patterson Cos Inc	PDCO	0.02%	1.93%	0.00%	9.50%	0.00%
QUALCOMM Inc	QCOM	0.39%	3.94%	0.02%	11.27%	0.04%
Roper Technologies Inc	ROP	0.10%	0.52%	0.00%	11.77%	0.01%
Ross Stores Inc	ROST	0.11%	0.90%	0.00%	10.79%	0.01%
AutoNation Inc	AN	0.04%	n/a	n/a	13.29%	0.00%
Starbucks Corp	SBUX	0.48%	1.30%	0.01%	18.16%	0.09%
KeyCorp	KEY	0.06%	2.29%	0.00%	7.34%	0.00%
Staples Inc	SPLS	0.04%	3.98%	0.00%	0.71%	0.00%
State Street Corp	STT	0.16%	1.87%	0.00%	8.62%	0.01%
US Bancorp	USB	0.41%	2.32%	0.01%	5.75%	0.02%
Symantec Corp	SYMC	0.07%	3.06%	0.00%	6.72%	0.00%
T Rowe Price Group Inc	TROW	0.10%	2.73%	0.00%	10.83%	0.01%
Waste Management Inc	WM	0.13%	2.86%	0.00%	7.98%	0.01%
CBS Corp	CBS	0.12%	1.19%	0.00%	14.02%	0.02%
Allergan plc	AGN	0.65%	n/a	n/a	11.91%	0.08%
Whole Foods Market Inc	WFM	0.05%	1.85%	0.00%	10.96%	0.01%
Constellation Brands Inc	STZ	0.13%	0.88%	0.00%	13.62%	0.02%
Xilinx Inc	XLNX	0.07%	2.50%	0.00%	8.12%	0.01%
DENTSPLY International Inc	XRAY	0.04%	0.48%	0.00%	9.07%	0.00%
Zions Bancorporation	ZION	0.03%	0.80%	0.00%	7.15%	0.00%
Invesco Ltd	IVZ	0.08%	3.21%	0.00%	10.48%	0.01%
Intuit Inc	INTU	0.14%	1.20%	0.00%	17.57%	0.02%
Morgan Stanley	MS	0.35%	1.75%	0.01%	17.07%	0.06%
Microchip Technology Inc	MCHP	0.05%	2.97%	0.00%	7.51%	0.00%
ACE Ltd	ACE	0.20%	2.33%	0.00%	11.20%	0.02%
Chesapeake Energy Corp	CHK	0.02%	n/a	n/a	0.28%	0.00%
O'Reilly Automotive Inc	ORLY	0.14%	n/a	n/a	17.70%	0.02%
Allstate Corp/The	ALL	0.13%	1.91%	0.00%	9.00%	0.01%
FLIR Systems Inc	FLIR	0.02%	1.44%	0.00%	15.00%	0.00%
Equity Residential	EQR	0.15%	2.77%	0.00%	5.99%	0.01%
BorgWarner Inc	BWA	0.05%	1.22%	0.00%	10.59%	0.01%
Newfield Exploration Co	NFX	0.03%	n/a	n/a	6.86%	0.00%
Urban Outfitters Inc	URBN	0.01%	n/a	n/a	13.26%	0.00%
Simon Property Group Inc	SPG	0.31%	3.44%	0.01%	6.75%	0.02%
Eastman Chemical Co	EMN	0.06%	2.20%	0.00%	7.03%	0.00%
AvalonBay Communities Inc	AVB	0.13%	2.75%	0.00%	6.13%	0.01%
Prudential Financial Inc	PRU	0.21%	3.24%	0.01%	11.00%	0.02%
United Parcel Service Inc	UPS	0.38%	2.83%	0.01%	11.44%	0.04%
Apartment Investment & Management Co	AIV	0.03%	3.15%	0.00%	8.34%	0.00%
Walgreens Boots Alliance Inc	WBA	0.48%	1.71%	0.01%	15.90%	0.08%
McKesson Corp	MCK	0.23%	0.59%	0.00%	14.73%	0.03%
Lockheed Martin Corp	LMT	0.36%	3.01%	0.01%	7.80%	0.03%
AmerisourceBergen Corp	ABC	0.11%	1.38%	0.00%	12.50%	0.01%
Cameron International Corp	CAM	0.07%	n/a	n/a	-5.90%	0.00%
Capital One Financial Corp	COF	0.22%	2.04%	0.00%	6.62%	0.01%
Waters Corp	WAT	0.06%	n/a	n/a	9.59%	0.01%
Dollar Tree Inc	DLTR	0.09%	n/a	n/a	19.67%	0.02%
Darden Restaurants Inc	DRI	0.04%	3.92%	0.00%	12.50%	0.00%
SanDisk Corp	SNDK	0.08%	n/a	n/a	11.00%	0.01%
Diamond Offshore Drilling Inc	DO	0.02%	2.21%	0.00%	13.40%	0.00%
NetApp Inc	NTAP	0.05%	2.35%	0.00%	9.98%	0.00%
Citrix Systems Inc	CTXS	0.06%	n/a	n/a	14.38%	0.01%
Goodyear Tire & Rubber Co/The	GT	0.05%	0.80%	0.00%	7.00%	0.00%

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.
DaVita HealthCare Partners Inc	DVA	0.08%	n/a	n/a	9.29%	0.01%
Hartford Financial Services Group Inc/The	HIG	0.10%	1.84%	0.00%	9.25%	0.01%
Iron Mountain Inc	IRM	0.03%	6.98%	0.00%	7.30%	0.00%
Estee Lauder Cos Inc/The	EL	0.10%	1.43%	0.00%	12.36%	0.01%
Yahoo! Inc	YHOO	0.17%	n/a	n/a	10.25%	0.02%
Principal Financial Group Inc	PFG	0.08%	2.95%	0.00%	11.50%	0.01%
Stericycle Inc	SRCL	0.05%	n/a	n/a	15.40%	0.01%
Universal Health Services Inc	UHS	0.06%	0.33%	0.00%	10.35%	0.01%
E*TRADE Financial Corp	ETFC	0.05%	n/a	n/a	16.36%	0.01%
Skyworks Solutions Inc	SWKS	0.08%	1.25%	0.00%	18.90%	0.02%
National Oilwell Varco Inc	NOV	0.07%	4.93%	0.00%	-5.45%	0.00%
Quest Diagnostics Inc	DGX	0.05%	2.22%	0.00%	10.46%	0.01%
Activision Blizzard Inc	ATVI	0.15%	0.61%	0.00%	11.33%	0.02%
Rockwell Automation Inc	ROK	0.07%	2.72%	0.00%	8.98%	0.01%
Kraft Heinz Co/The	KHC	0.47%	3.12%	0.01%	15.87%	0.08%
American Tower Corp	AMT	0.22%	1.85%	0.00%	14.88%	0.03%
Regeneron Pharmaceuticals Inc	REGN	0.29%	n/a	n/a	21.69%	0.06%
Amazon.com Inc	AMZN	1.65%	n/a	n/a	62.40%	1.03%
Ralph Lauren Corp	RL	0.04%	1.61%	0.00%	12.85%	0.00%
Boston Properties Inc	BXP	0.10%	2.08%	0.00%	6.06%	0.01%
Amphenol Corp	APH	0.09%	1.02%	0.00%	8.70%	0.01%
Pioneer Natural Resources Co	PXD	0.11%	0.06%	0.00%	5.60%	0.01%
Valero Energy Corp	VLO	0.18%	2.78%	0.01%	2.79%	0.01%
L-3 Communications Holdings Inc	LLL	0.05%	2.12%	0.00%	6.69%	0.00%
Western Union Co/The	WU	0.05%	3.29%	0.00%	6.73%	0.00%
CH Robinson Worldwide Inc	CHRW	0.05%	2.25%	0.00%	10.63%	0.01%
Accenture PLC	ACN	0.35%	2.05%	0.01%	10.37%	0.04%
Yum! Brands Inc	YUM	0.17%	2.54%	0.00%	11.45%	0.02%
Prologis Inc	PLD	0.12%	3.74%	0.00%	4.77%	0.01%
FirstEnergy Corp	FE	0.07%	4.59%	0.00%	-0.30%	0.00%
VeriSign Inc	VRSN	0.05%	n/a	n/a	8.40%	0.00%
Quanta Services Inc	PWR	0.02%	n/a	n/a	8.00%	0.00%
Henry Schein Inc	HSIC	0.07%	n/a	n/a	10.78%	0.01%
Ameren Corp	AEE	0.06%	3.88%	0.00%	7.10%	0.00%
Broadcom Corp	BRCM	0.16%	1.03%	0.00%	12.36%	0.02%
NVIDIA Corp	NVDA	0.09%	1.45%	0.00%	8.53%	0.01%
Sealed Air Corp	SEE	0.05%	1.15%	0.00%	9.50%	0.00%
Cognizant Technology Solutions Corp	CTSH	0.21%	n/a	n/a	16.28%	0.03%
Intuitive Surgical Inc	ISRG	0.10%	n/a	n/a	14.53%	0.01%
CONSOL Energy Inc	CNX	0.01%	0.51%	0.00%	14.40%	0.00%
Affiliated Managers Group Inc	AMG	0.05%	n/a	n/a	13.01%	0.01%
Aetna Inc	AET	0.19%	0.97%	0.00%	11.95%	0.02%
Republic Services Inc	RSG	0.08%	2.73%	0.00%	6.77%	0.01%
eBay Inc	EBAY	0.19%	n/a	n/a	7.25%	0.01%
Goldman Sachs Group Inc/The	GS	0.43%	1.37%	0.01%	8.31%	0.04%
Sempra Energy	SRE	0.13%	2.82%	0.00%	8.35%	0.01%
Moody's Corp	MCO	0.11%	1.32%	0.00%	13.00%	0.01%
Priceline Group Inc/The	PCLN	0.33%	n/a	n/a	18.71%	0.06%
F5 Networks Inc	FFIV	0.04%	n/a	n/a	15.90%	0.01%
Akamai Technologies Inc	AKAM	0.05%	n/a	n/a	15.40%	0.01%
Reynolds American Inc	RAI	0.35%	3.11%	0.01%	6.48%	0.02%
Devon Energy Corp	DVN	0.10%	2.09%	0.00%	6.99%	0.01%
Alphabet Inc	GOOGL	1.18%	n/a	n/a	18.08%	0.21%
Red Hat Inc	RHT	0.08%	n/a	n/a	18.58%	0.01%
Allegion PLC	ALLE	0.03%	0.60%	0.00%	14.89%	0.01%
Netflix Inc	NFLX	0.28%	n/a	n/a	27.33%	0.08%
Agilent Technologies Inc	A	0.07%	1.10%	0.00%	11.80%	0.01%
Anthem Inc	ANTM	0.18%	1.92%	0.00%	9.61%	0.02%
CME Group Inc/IL	CME	0.17%	2.05%	0.00%	12.61%	0.02%
Juniper Networks Inc	JNPR	0.06%	1.33%	0.00%	11.38%	0.01%
BlackRock Inc	BLK	0.32%	2.40%	0.01%	11.97%	0.04%
DTE Energy Co	DTE	0.08%	3.63%	0.00%	5.30%	0.00%
Nasdaq Inc	NDAQ	0.05%	1.71%	0.00%	6.88%	0.00%
Philip Morris International Inc	PM	0.72%	4.67%	0.03%	6.12%	0.04%
Time Warner Cable Inc	TWC	0.28%	1.62%	0.00%	5.50%	0.02%
salesforce.com inc	CRM	0.28%	n/a	n/a	27.72%	0.08%
MetLife Inc	MET	0.30%	2.94%	0.01%	7.38%	0.02%
Monsanto Co	MON	0.22%	2.27%	0.01%	9.82%	0.02%
Coach Inc	COH	0.05%	4.25%	0.00%	10.67%	0.00%
Fluor Corp	FLR	0.04%	1.73%	0.00%	5.73%	0.00%
Dun & Bradstreet Corp/The	DNB	0.02%	1.72%	0.00%	10.15%	0.00%
Edwards Lifesciences Corp	EW	0.09%	n/a	n/a	15.20%	0.01%
Ameriprise Financial Inc	AMP	0.10%	2.37%	0.00%	13.00%	0.01%
Xcel Energy Inc	XEL	0.10%	3.59%	0.00%	4.75%	0.00%
Rockwell Collins Inc	COL	0.06%	1.42%	0.00%	7.97%	0.01%
FMC Technologies Inc	FTI	0.04%	n/a	n/a	-11.80%	0.00%
Zimmer Biomet Holdings Inc	ZBH	0.11%	0.87%	0.00%	10.48%	0.01%
CBRE Group Inc	CBG	0.07%	n/a	n/a	10.50%	0.01%
MasterCard Inc	MA	0.57%	0.65%	0.00%	16.50%	0.09%
Signet Jewelers Ltd	SIG	0.06%	0.67%	0.00%	12.50%	0.01%
GameStop Corp	GME	0.02%	4.11%	0.00%	12.74%	0.00%
CarMax Inc	KMX	0.06%	n/a	n/a	15.27%	0.01%
Intercontinental Exchange Inc	ICE	0.15%	1.15%	0.00%	15.83%	0.02%
Fidelity National Information Services Inc	FIS	0.10%	1.63%	0.00%	12.78%	0.01%
Chipotle Mexican Grill Inc	CMG	0.10%	n/a	n/a	19.93%	0.02%
Pepco Holdings Inc	POM	0.03%	4.21%	0.00%	5.53%	0.00%
Wynn Resorts Ltd	WYNN	0.03%	3.19%	0.00%	8.93%	0.00%
Assurant Inc	AIZ	0.03%	2.34%	0.00%	8.62%	0.00%
NRG Energy Inc	NRG	0.02%	4.69%	0.00%	26.60%	0.01%
Regions Financial Corp	RF	0.07%	2.37%	0.00%	2.08%	0.00%
Monster Beverage Corp	MNST	0.17%	n/a	n/a	16.63%	0.03%

STANDARD AND POOR'S 500 INDEX

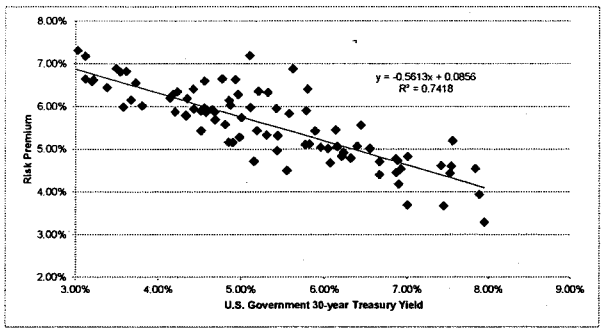
Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
Teradata Corp	TDC	0.02%	n/a	n/a	8.22%	0.00%
Mosaic Co/The	MOS	0.06%	3.48%	0.00%	15.37%	0.01%
Expedia Inc	EXPE	0.08%	0.78%	0.00%	21.25%	0.02%
Discovery Communications Inc	DISCA	0.02%	n/a	n/a	15.50%	0.00%
CF Industries Holdings Inc	CF	0.06%	2.60%	0.00%	20.00%	0.01%
Viacom Inc	VIAB	0.09%	3.21%	0.00%	9.10%	0.01%
Wyndham Worldwide Corp	WYN	0.05%	2.21%	0.00%	9.00%	0.00%
Alphabet Inc	GOOG	1.36%	n/a	n/a	18.08%	0.25%
Spectra Energy Corp	SE	0.09%	5.65%	0.01%	4.63%	0.00%
First Solar Inc	FSLR	0.03%	n/a	n/a	1.03%	0.00%
Mead Johnson Nutrition Co	MJN	0.08%	2.05%	0.00%	8.80%	0.01%
Ensco PLC	ESV	0.02%	3.50%	0.00%	-4.00%	0.00%
TE Connectivity Ltd	TEL	0.14%	1.97%	0.00%	10.00%	0.01%
Discover Financial Services	DFS	0.13%	1.97%	0.00%	8.59%	0.01%
TripAdvisor Inc	TRIP	0.06%	n/a	n/a	15.73%	0.01%
Dr Pepper Snapple Group Inc	DPS	0.09%	2.14%	0.00%	7.70%	0.01%
Scripps Networks Interactive Inc	SNI	0.03%	1.62%	0.00%	11.46%	0.00%
Visa Inc	V	0.81%	0.71%	0.01%	17.37%	0.14%
Xylem Inc/NY	XYL	0.04%	1.51%	0.00%	11.30%	0.00%
Marathon Petroleum Corp	MPC	0.16%	2.19%	0.00%	2.62%	0.00%
Level 3 Communications Inc	LVLT	0.10%	n/a	n/a	8.00%	0.01%
Tractor Supply Co	TSCO	0.06%	0.90%	0.00%	15.69%	0.01%
Transocean Ltd	RIG	0.03%	n/a	n/a	26.29%	0.01%
Essex Property Trust Inc	ESS	0.08%	2.50%	0.00%	6.25%	0.01%
General Growth Properties Inc	GGP	0.12%	2.98%	0.00%	7.05%	0.01%
Realty Income Corp	O	0.07%	4.61%	0.00%	4.30%	0.00%
Seagate Technology PLC	STX	0.06%	7.01%	0.00%	7.06%	0.00%
WestRock Co	WRK	0.07%	2.96%	0.00%	n/a	n/a
Western Digital Corp	WDC	0.08%	3.20%	0.00%	5.00%	0.00%
Twenty-First Century Fox Inc	FOX	0.13%	1.00%	0.00%	14.92%	0.02%
Comcast Corp	CMCSK	0.11%	1.64%	0.00%	13.39%	0.02%
Fossil Group Inc	FOSL	0.01%	n/a	n/a	0.00%	0.00%
JB Hunt Transport Services Inc	JBHT	0.05%	1.07%	0.00%	14.13%	0.01%
Lam Research Corp	LRCX	0.07%	1.53%	0.00%	5.48%	0.00%
Mohawk Industries Inc	MHK	0.07%	n/a	n/a	12.00%	0.01%
Pentair PLC	PNR	0.05%	2.26%	0.00%	7.23%	0.00%
Vertex Pharmaceuticals Inc	VRTX	0.17%	n/a	n/a	30.00%	0.05%
Facebook Inc	FB	1.25%	n/a	n/a	28.98%	0.36%
United Rentals Inc	URI	0.04%	n/a	n/a	12.64%	0.00%
United Continental Holdings Inc	UAL	0.11%	n/a	n/a	19.72%	0.02%
Baxalta Inc	BXLT	0.12%	0.81%	0.00%	2.30%	0.00%
Delta Air Lines Inc	DAL	0.19%	1.16%	0.00%	21.88%	0.04%
Navient Corp	NAVI	0.02%	5.37%	0.00%	n/a	n/a
Mallinckrodt PLC	MNK	0.04%	n/a	n/a	13.19%	0.01%
News Corp	NWS	0.02%	1.38%	0.00%	13.95%	0.00%
Keurig Green Mountain Inc	GMCR	0.04%	2.48%	0.00%	12.08%	0.00%
Macerich Co/The	MAC	0.07%	3.48%	0.00%	5.70%	0.00%
Martin Marietta Materials Inc	MLM	0.06%	1.02%	0.00%	18.99%	0.01%
PayPal Holdings Inc	PYPL	0.23%	n/a	n/a	16.33%	0.04%
Alexion Pharmaceuticals Inc	ALXN	0.21%	n/a	n/a	21.71%	0.05%
Columbia Pipeline Group Inc	CPGX	0.03%	2.61%	0.00%	36.00%	0.01%
Endo International PLC	ENDP	0.07%	n/a	n/a	12.13%	0.01%
News Corp	NWSA	0.03%	1.39%	0.00%	13.95%	0.00%
Crown Castle International Corp	CCI	0.15%	4.12%	0.01%	22.80%	0.03%
Delphi Automotive PLC	DLPH	0.13%	1.14%	0.00%	10.61%	0.01%
Advance Auto Parts Inc	AAP	0.06%	0.15%	0.00%	11.95%	0.01%
Michael Kors Holdings Ltd	KORS	0.04%	n/a	n/a	7.45%	0.00%
Illumina Inc	ILMN	0.14%	n/a	n/a	20.48%	0.03%
Alliance Data Systems Corp	ADS	0.09%	n/a	n/a	14.50%	0.01%
Nielsen Holdings PLC	NLSN	0.09%	2.40%	0.00%	12.33%	0.01%
Garmin Ltd	GRMN	0.04%	5.39%	0.00%	8.45%	0.00%
Cimarex Energy Co	XEC	0.06%	0.54%	0.00%	-2.79%	0.00%
Zoetis Inc	ZTS	0.12%	0.71%	0.00%	9.85%	0.01%
Equinix Inc	EQIX	0.10%	2.28%	0.00%	17.00%	0.02%
Discovery Communications Inc	DISCK	0.04%	n/a	n/a	15.50%	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-R-6

BOND YIELD PLUS RISK PREMIUM

	[1] Average Authorized Electric ROE	[2] 30-year U.S. Treasury Bond	[3] 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	9.66%	2.45%	7.21%
2015.2	9.50%	2.92%	6.58%
2015.3	9.40%	2.91%	6.49%
2015.4	9.77%	2.95%	6.82%
AVERAGE	10.80%	5.11%	5.69%
MEDIAN	10.73%	4.97%	5.82%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.861251
R Square	0.741754
Adjusted R Square	0.739007
Standard Error	0.004667
Observations	96

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.005879	0.005879	269.993823	0.000000
Residual	94	0.002047	0.000022		
Total	95	0.007926			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0856	0.001809	47.33	0.000000	0.082012	0.089193	0.082012	0.089193
30-year U.S. Treasury Bond	(0.5613)	0.034160	(16.43)	0.000000	(0.629122)	(0.493472)	(0.629122)	(0.493472)

	[7] U.S. Govt. 30-year Treasury	[8] Risk Premium	[9] ROE
Current 30-Day Average [4]	2.98%	6.89%	9.87%
Blue Chip Consensus Forecast (Q1 2015-Q2 2016) [5]	3.37%	6.67%	10.04%
Blue Chip Consensus Forecast (2016-2020) [6]	4.80%	5.87%	10.67%
MEAN			10.19%

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. 11, November 1, 2015, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 34, No. 6, June 1, 2015, at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.085602 + (-0.561297 x Column [7])
[9] Equals Column [7] + Column [8]

Exhibit AEB-R-7

ADJUSTMENTS TO MEASE DCF - DCF 90 DAY CONSTANT GROWTH - ES & PNM YAHOO! EPS GROWTH RATES & EXCLUDES SO

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) ESTIMATED DIVIDEND PER SHARE	/	(B) AVERAGE STOCK PRICE (PER SHARE)		(C) DIVIDEND YIELD	(D) PROJECTED DIVIDEND YIELD	(E) FIVE YEAR GROWTH VALUE LINE	(F) YAHOO FINANCE	(G) AVERAGE EARNINGS GROWTH	(H) ROE LOW	(I) ROE MEAN	(J) ROE HIGH
1	ALE	ALLETE, Inc.	$ 2.02		$ 48.28	=	4.18%	4.28%	4.00%	5.50%	4.75%	8.27%	9.03%	9.80%
2	AEP	American Electric Power Company, Inc.	$ 2.12		$ 55.29	=	3.83%	3.93%	5.00%	4.63%	4.82%	8.55%	8.74%	8.93%
3	DUK	Duke Energy Corporation	$ 3.30		$ 72.04	=	4.58%	4.67%	3.50%	4.04%	3.77%	8.16%	8.44%	8.71%
4	EE	El Paso Electric Company	$ 1.18		$ 35.62	=	3.31%	3.41%	5.00%	7.00%	6.00%	8.40%	9.41%	10.43%
5	EDE	Empire District Electric Company	$ 1.04		$ 22.11	=	4.70%	4.79%	3.00%	4.00%	3.50%	7.77%	8.29%	8.80%
6	ES	Eversource Energy	$ 1.67		$ 47.84	=	3.49%	3.60%	6.50%	5.85%	6.18%	9.45%	9.78%	10.11%
7	GXP	Great Plains Energy Inc.	$ 0.98		$ 25.42	=	3.86%	3.97%	6.00%	6.37%	6.19%	9.97%	10.16%	10.35%
8	IDA	IDACORP, Inc.	$ 1.88		$ 60.13	=	3.13%	3.20%	6.00%	4.00%	5.00%	7.19%	8.20%	9.22%
9	OTTR	Otter Tail Corporation	$ 1.23		$ 26.28	=	4.69%	4.78%	1.50%	6.00%	3.75%	6.22%	8.53%	10.83%
10	PNW	Pinnacle West Capital Corporation	$ 2.38		$ 60.93	=	3.91%	3.99%	3.50%	5.37%	4.44%	7.47%	8.43%	9.38%
11	PNM	PNM Resources, Inc.	$ 0.80		$ 25.85	=	3.09%	3.24%	10.00%	8.56%	9.28%	11.79%	12.52%	13.25%
12	POR	Portland General Electric Company	$ 1.20		$ 34.97	=	3.43%	3.51%	5.50%	3.92%	4.71%	7.42%	8.22%	9.03%
13	WR	Westar Energy, Inc.	$ 1.44		$ 36.66	=	3.93%	3.99%	3.00%	3.40%	3.20%	6.99%	7.19%	7.39%
		Average					3.86%	3.95%	4.81%	5.28%	5.04%	8.28%	9.00%	9.71%

AVERAGE OF LOW, MEAN AND HIGH 9.00%

REFERENCES:
COLUMN (A): ANNUALIZED DIVIDENDS PER VALUE LINE
COLUMN (B): AVERAGE STOCK PRICES, SEE ROBERT MEASE TESTIMONY ATTACHMENT (C)
COLUMN (C): COLUMN (A) / COLUMN (B)
COLUMN (D): COLUMN (C) X (1 + .50 COLUMN (G))
COLUMN (G): AVERAGE OF COLUMN (E) AND (F)

ADJUSTMENTS TO MEASE DCF - DCF 90 DAY CONSTANT GROWTH - ES & PNM YAHOO! EPS GROWTH RATES, EXCLUDES SO & USES VALUE LINE EPS GROWTH RATES

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) ESTIMATED DIVIDEND PER SHARE	/	(B) AVERAGE STOCK PRICE (PER SHARE)		(C) DIVIDEND YIELD	(D) PROJECTED DIVIDEND YIELD	(E) FIVE YEAR GROWTH VALUE LINE	(F) YAHOO FINANCE	(G) AVERAGE EARNINGS GROWTH	(H) ROE LOW	(I) ROE MEAN	(J) ROE HIGH
1	ALE	ALLETE, Inc.	$ 2.02		$ 48.28	=	4.18%	4.31%	6.50%	5.50%	6.00%	9.80%	10.31%	10.82%
2	AEP	American Electric Power Company, Inc.	$ 2.12		$ 55.29	=	3.83%	3.93%	5.00%	4.63%	4.82%	8.55%	8.74%	8.93%
3	DUK	Duke Energy Corporation	$ 3.30		$ 72.04	=	4.58%	4.68%	5.00%	4.04%	4.52%	8.71%	9.20%	9.70%
4	EE	El Paso Electric Company	$ 1.18		$ 35.62	=	3.31%	3.40%	3.50%	7.00%	5.25%	6.87%	8.65%	10.43%
5	EDE	Empire District Electric Company	$ 1.04		$ 22.11	=	4.70%	4.79%	3.00%	4.00%	3.50%	7.77%	8.29%	8.80%
6	ES	Eversource Energy	$ 1.67		$ 47.84	=	3.49%	3.62%	8.50%	5.85%	7.18%	9.45%	10.80%	12.14%
7	GXP	Great Plains Energy Inc.	$ 0.98		$ 25.42	=	3.86%	3.96%	5.00%	6.37%	5.69%	8.95%	9.65%	10.35%
8	IDA	IDACORP, Inc.	$ 1.88		$ 60.13	=	3.13%	3.17%	1.00%	4.00%	2.50%	4.14%	5.67%	7.19%
9	OTTR	Otter Tail Corporation	$ 1.23		$ 26.28	=	4.69%	4.86%	9.00%	6.00%	7.50%	10.83%	12.36%	13.90%
10	PNW	Pinnacle West Capital Corporation	$ 2.38		$ 60.93	=	3.91%	4.00%	4.00%	5.37%	4.69%	7.98%	8.68%	9.38%
11	PNM	PNM Resources, Inc.	$ 0.80		$ 25.85	=	3.09%	3.23%	9.00%	8.56%	8.78%	11.79%	12.01%	12.23%
12	POR	Portland General Electric Company	$ 1.20		$ 34.97	=	3.43%	3.52%	6.00%	3.92%	4.96%	7.42%	8.48%	9.53%
13	WR	Westar Energy, Inc.	$ 1.44		$ 36.66	=	3.93%	4.02%	6.00%	3.40%	4.70%	7.39%	8.72%	10.05%
		Average					3.86%	3.96%	5.50%	5.28%	5.39%	8.44%	9.35%	10.27%

AVERAGE OF LOW, MEAN AND HIGH 9.35%

REFERENCES:
COLUMN (A): ANNUALIZED DIVIDENDS PER VALUE LINE
COLUMN (B): AVERAGE STOCK PRICES, SEE ROBERT MEASE TESTIMONY ATTACHMENT (C)
COLUMN (C): COLUMN (A) / COLUMN (B)
COLUMN (D): COLUMN (C) X (1 + .50 COLUMN (G))
COLUMN (G): AVERAGE OF COLUMN (E) AND (F)

ADJUSTMENTS TO MEASE DCF - DCF 90 DAY CONSTANT GROWTH - EXCLUDES SO & USES SEPTEMBER VALUE LINE & YAHOO! EPS GROWTH RATES

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) ESTIMATED DIVIDEND PER SHARE	/	(B) AVERAGE STOCK PRICE (PER SHARE)		(C) DIVIDEND YIELD	(D) PROJECTED DIVIDEND YIELD	(E) FIVE YEAR GROWTH VALUE LINE	(F) YAHOO FINANCE	(G) AVERAGE EARNINGS GROWTH	(H) ROE LOW	(I) ROE MEAN	(J) ROE HIGH
1	ALE	ALLETE, Inc.	$ 2.02		$ 48.28	=	4.18%	4.31%	6.50%	6.00%	6.25%	10.31%	10.56%	10.82%
2	AEP	American Electric Power Company, Inc.	$ 2.12		$ 55.29	=	3.83%	3.93%	5.00%	4.63%	4.82%	8.55%	8.74%	8.93%
3	DUK	Duke Energy Corporation	$ 3.30		$ 72.04	=	4.58%	4.69%	5.00%	4.33%	4.67%	9.01%	9.35%	9.70%
4	EE	El Paso Electric Company	$ 1.18		$ 35.62	=	3.31%	3.40%	3.50%	7.00%	5.25%	6.87%	8.65%	10.43%
5	EDE	Empire District Electric Company	$ 1.04		$ 22.11	=	4.70%	4.77%	3.00%	3.00%	3.00%	7.77%	7.77%	7.77%
6	ES	Eversource Energy	$ 1.67		$ 47.84	=	3.49%	3.62%	8.50%	6.21%	7.36%	9.81%	10.98%	12.14%
7	GXP	Great Plains Energy Inc.	$ 0.98		$ 25.42	=	3.86%	3.96%	5.00%	6.37%	5.69%	8.95%	9.65%	10.35%
8	IDA	IDACORP, Inc.	$ 1.88		$ 60.13	=	3.13%	3.17%	1.00%	4.00%	2.50%	4.14%	5.67%	7.19%
9	OTTR	Otter Tail Corporation	$ 1.23		$ 26.28	=	4.69%	4.86%	9.00%	6.00%	7.50%	10.83%	12.36%	13.90%
10	PNW	Pinnacle West Capital Corporation	$ 2.38		$ 60.93	=	3.91%	4.00%	4.00%	5.37%	4.69%	7.98%	8.68%	9.38%
11	PNM	PNM Resources, Inc.	$ 0.80		$ 25.85	=	3.09%	3.23%	9.00%	8.56%	8.78%	11.79%	12.01%	12.23%
12	POR	Portland General Electric Company	$ 1.20		$ 34.97	=	3.43%	3.52%	6.00%	4.07%	5.04%	7.57%	8.55%	9.53%
13	WR	Westar Energy, Inc.	$ 1.44		$ 36.66	=	3.93%	4.02%	6.00%	3.40%	4.70%	7.39%	8.72%	10.05%
		Average					3.86%	3.96%	5.50%	5.30%	5.40%	8.54%	9.36%	10.19%

AVERAGE OF LOW, MEAN AND HIGH 9.36%

REFERENCES:
COLUMN (A): ANNUALIZED DIVIDENDS PER VALUE LINE
COLUMN (B): AVERAGE STOCK PRICES, SEE ROBERT MEASE TESTIMONY ATTACHMENT (C)
COLUMN (C): COLUMN (A) / COLUMN (B)
COLUMN (D): COLUMN (C) X (1 + .50 COLUMN (G))
COLUMN (G): AVERAGE OF COLUMN (E) AND (F)

Exhibit AEB-R-8

ADJUSTMENTS TO MEASE CAPM - BASED ON AN ARITHMETIC MEAN - USING CURRENT INTEREST RATE, EXCLUDING SOUTHERN COMPANY & USING UPDATED MARKET RETURN

LINE NO.	STOCK SYMBOL	COMPANY NAME														(A)	(B) EXPECTED RETURN
			k	=	r_f	+	[	β	x	(	r_m	-	r_f	)	]	=	
1	ALE	ALLETE, Inc.	k	=	3.01%	+	[	0.80	x	(	12.10%	-	3.01%	)	]	=	10.28%
2	AEP	American Electric Power Company, Inc.	k	=	3.01%	+	[	0.70	x	(	12.10%	-	3.01%	)	]	=	9.37%
3	DUK	Duke Energy Corporation	k	=	3.01%	+	[	0.60	x	(	12.10%	-	3.01%	)	]	=	8.46%
4	EE	El Paso Electric Company	k	=	3.01%	+	[	0.75	x	(	12.10%	-	3.01%	)	]	=	9.83%
5	EDE	Empire District Electric Company	k	=	3.01%	+	[	0.70	x	(	12.10%	-	3.01%	)	]	=	9.37%
6	ES	Eversource Energy	k	=	3.01%	+	[	0.75	x	(	12.10%	-	3.01%	)	]	=	9.83%
7	GXP	Great Plains Energy Inc.	k	=	3.01%	+	[	0.85	x	(	12.10%	-	3.01%	)	]	=	10.74%
8	IDA	IDACORP, Inc.	k	=	3.01%	+	[	0.80	x	(	12.10%	-	3.01%	)	]	=	10.28%
9	OTTR	Otter Tail Corporation	k	=	3.01%	+	[	0.85	x	(	12.10%	-	3.01%	)	]	=	10.74%
10	PNW	Pinnacle West Capital Corporation	k	=	3.01%	+	[	0.70	x	(	12.10%	-	3.01%	)	]	=	9.37%
11	PNM	PNM Resources, Inc.	k	=	3.01%	+	[	0.85	x	(	12.10%	-	3.01%	)	]	=	10.74%
12	POR	Portland General Electric Company	k	=	3.01%	+	[	0.80	x	(	12.10%	-	3.01%	)	]	=	10.28%
13	WR	Westar Energy, Inc.	k	=	3.01%	+	[	0.75	x	(	12.10%	-	3.01%	)	]	=	9.83%
14	**AVERAGE**							0.76									9.93%

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$$k = r_f + [\beta (r_m - r_f)]$$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
β = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)
r_f = PROXY FOR THE RISK FREE RATE ON LONG-TERM TREASURIES (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

Exhibit AEB-R-9

UNS ELECTRIC
FAIR VALUE RATE OF RETURN
RUCO PROPOSED METHODOLOGY

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

FVROR Adjusted for 50% Inflation Factor

Capital	Amount ($M)	Percent	Cost Rate	Weighted Cost Rate
Proposed Equity Ratio		47.17% [3]		
Proposed Debt Ratio		52.83% [4]		
Inflation Rate		1.35% [5]	0.68%	
Debt Cost Rate			4.66%	
Equity Cost Rate			8.35%	
Long-Term Debt	$ 167.8 [6]	47.17%	3.99% [8]	1.88%
Common Equity	187.9 [7]	52.83%	7.68% [9]	4.05%
Capital Financing FVRB	$ 355.7	100.00%		5.93%

[1] Direct Testimony of Dallas J. Dukes, Schedule B-1
[2] Direct Testimony of Dallas J. Dukes, Schedule B-1
[3] JMM-2
[4] JMM-2
[5] JMM-1
[6] =[1]*[3]
[7] = [1]*[4]
[8] = [5]*.5*debt cost rate
[9] = Equity cost rate -([3]*.5)

FVROR Adjusted for 50% Inflation Factor and Adjusted ROE

Capital	Amount ($M)	Percent	Cost Rate	Weighted Cost Rate
Proposed Equity Ratio		47.17% [3]		
Proposed Debt Ratio		52.83% [4]		
Inflation Rate		1.35% [5]	0.68%	
Debt Cost Rate			4.66%	
Equity Cost Rate			9.36%	
Long-Term Debt	$ 167.8 [6]	47.17%	3.99% [8]	1.88%
Common Equity	187.9 [7]	52.83%	8.69% [9]	4.59%
Capital Financing FVRB	$ 355.7	100.00%		6.47%

[1] Direct Testimony of Dallas J. Dukes, Schedule B-1
[2] Direct Testimony of Dallas J. Dukes, Schedule B-1
[3] JMM-2
[4] JMM-2
[5] JMM-1
[6] =[1]*[3]
[7] = [1]*[4]
[8] = [5]*.5*debt cost rate
[9] = Equity cost rate -([3]*.5)

Exhibit AEB-R-10

ADJUSTMENTS TO WOOLRIDGE DCF EQUITY COST GROWTH RATE MEASURES
VALUE LINE PROJECTED GROWTH RATES

	Company	[1] Earnings	[2] *Value Line* Projected Growth Est'd. '12-'14 to '18-'20 Dividends	[3] Book Value	[4] Return on Equity	[5] *Value Line* Sustainable Growth Retention Rate	[6] Internal Growth	[7] Shares Out	[8] Value Change	[9] S x V	[10] BR + SV
1	ALLETE, Inc. (NYSE-ALE)	6.50%	4.00%	4.50%	9.00%	39.00%	3.5%	2.1%	19.0%	0.4%	3.9%
2	Alliant Energy Corporation (NYSE-LNT)	6.00%	4.50%	4.00%	11.50%	37.00%	4.3%	1.4%	46.7%	0.6%	4.9%
3	Ameren Corporation (NYSE-AEE)	7.00%	3.50%	3.50%	10.50%	44.00%	4.6%	0.8%	20.0%	0.2%	4.8%
4	American Electric Power Co. (NYSE-AEP)	5.00%	5.00%	4.00%	10.00%	34.00%	3.4%	0.6%	30.0%	0.2%	3.6%
5	Avista Corporation (NYSE-AVA)	5.00%	4.00%	3.50%	8.50%	35.00%	3.0%	0.7%	22.1%	0.2%	3.1%
6	Black Hills Corporation (NYSE-BKH)	4.50%	4.00%	3.50%	8.50%	40.00%	3.4%	0.8%	30.5%	0.3%	3.7%
7	CMS Energy Corporation (NYSE-CMS)	5.50%	6.50%	5.50%	13.50%	38.00%	5.1%	1.4%	49.3%	0.7%	5.8%
8	Consolidated Edison, Inc. (NYSE-ED)	3.00%	2.50%	3.50%	9.00%	36.00%	3.2%	0.0%	18.8%	0.0%	3.2%
9	Dominion Resources, Inc. (NYSE-D)	8.00%	7.50%	6.50%	17.50%	28.00%	4.9%	4.4%	66.1%	2.9%	7.8%
10	Duke Energy Corporation (NYSE-DUK)	5.00%	3.50%	1.50%	8.50%	30.00%	2.6%	-0.5%	22.1%	-0.1%	2.4%
11	Edison International (NYSE-EIX)	3.00%	10.00%	6.50%	11.50%	48.00%	5.5%	0.0%	36.1%	0.0%	5.5%
12	El Paso Electric Company (NYSE-EE)	3.50%	5.00%	4.50%	9.50%	50.00%	4.8%	0.5%	26.3%	0.1%	4.9%
13	Empire District Electric Co. (NYSE-EDE)	3.00%	3.00%	2.50%	9.00%	33.00%	3.0%	2.2%	19.0%	0.4%	3.4%
14	Entergy Corporation (NYSE-ETR)	0.00%	2.50%	3.00%	8.50%	31.00%	2.6%	0.0%	25.0%	0.0%	2.6%
15	Eversource Energy (NYSE-ES)	8.50%	6.50%	4.00%	10.00%	44.00%	4.4%	0.4%	27.1%	0.1%	4.5%
16	FirstEnergy Corporation (ASE-FE)	7.00%	-1.50%	3.00%	8.50%	48.00%	4.1%	0.7%	5.3%	0.0%	4.1%
17	Great Plains Energy Incorporated (NYSE-GXP)	5.00%	6.00%	3.00%	7.50%	39.00%	2.9%	0.2%	2.7%	0.0%	2.9%
18	IDACORP, Inc. (NYSE-IDA)	1.00%	6.00%	4.00%	8.50%	42.00%	3.6%	0.0%	24.7%	0.0%	3.6%
19	MGE Energy, Inc. (NYSE-MGEE)	7.00%	4.00%	6.00%	13.00%	58.00%	7.5%	1.4%	47.4%	0.7%	8.2%
20	NorthWestern Corporation (NYSE-NWE)	6.50%	6.50%	5.50%	10.00%	42.00%	4.2%	0.6%	27.6%	0.2%	4.4%
21	OGE Energy Corp. (NYSE-OGE)	3.00%	10.00%	5.00%	11.50%	32.00%	3.7%	0.4%	42.1%	0.2%	3.9%
22	Otter Tail Corporation (NDQ-OTTR)	9.00%	1.50%	3.50%	12.50%	41.00%	5.1%	5.4%	54.8%	3.0%	8.1%
23	PG&E Corporation (NYSE-PCG)	10.50%	3.00%	5.00%	10.00%	49.00%	4.9%	2.1%	15.0%	0.3%	5.2%
24	Pinnacle West Capital Corp. (NYSE-PNW)	4.00%	3.50%	3.50%	9.50%	36.00%	3.4%	1.7%	24.8%	0.4%	3.9%
25	PNM Resources, Inc. (NYSE-PNM)	9.00%	10.00%	3.50%	9.50%	51.00%	4.8%	0.1%	32.0%	0.0%	4.9%
26	Portland General Electric Company (NYSE-POR)	6.00%	5.50%	4.50%	9.50%	47.00%	4.5%	3.1%	12.9%	0.4%	4.9%
27	SCANA Corporation (NYSE-SCG)	4.50%	3.50%	5.50%	9.50%	44.00%	4.2%	1.1%	20.9%	0.2%	4.4%
28	Westar Energy, Inc. (NYSE-WR)	6.00%	3.00%	5.00%	9.50%	45.00%	4.3%	1.9%	35.0%	0.7%	4.9%
29	Xcel Energy Inc. (NYSE-XEL)	4.50%	6.00%	4.50%	10.50%	38.00%	4.0%	0.6%	29.3%	0.2%	4.2%
	Mean	5.4%	4.8%	4.2%	10.16%	40.66%	4.1%	1.2%	28.7%	0.4%	4.5%
	Median	5.0%	4.0%	4.0%	9.50%	40.00%	4.2%	0.7%	26.3%	0.2%	4.4%
	Average of Median Figures =		4.3%				4.2%				

Data Source: *Value Line Investment Survey.*

Exhibit AEB-R-11

ADJUSTMENTS TO WOOLRIDGE DCF EQUITY COST GROWTH RATE MEASURES
ANALYSTS PROJECTED EPS GROWTH RATE ESTIMATES

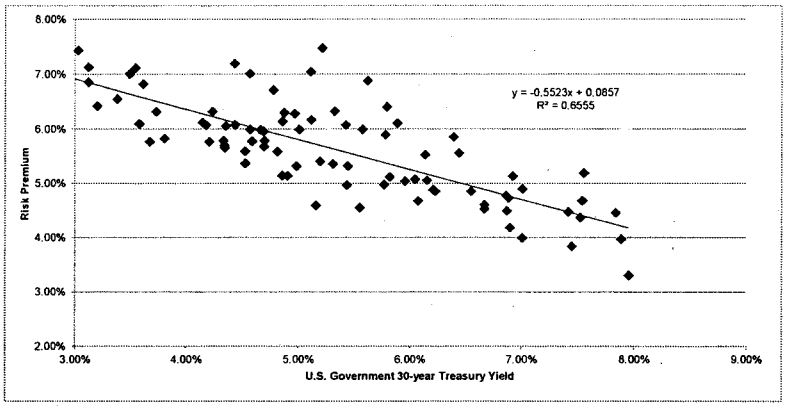
	Step 1: Exhibit JRW-10, page 5 of 6, EPS Growth Rates					Step 2: Add VL EPS Growth Rates from Exhibit JRW-10, page 4 of 6					Step 3: Removed six proxy companies for reasons stated					
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
	Company	Yahoo	Zacks	Reuters	Mean	Yahoo	Zacks	Reuters	Value Line	Mean	Yahoo	Zacks	Reuters	Value Line	Mean	Reason Removed
1	ALLETE, Inc. (NYSE-ALE)	6.0%	NA	NA	6.0%	6.0%	NA	NA	6.5%	6.3%	6.0%	NA	NA	6.5%	6.3%	
2	Alliant Energy Corporation (NYSE-LNT)	5.8%	5.3%	5.8%	5.6%	5.8%	5.3%	5.8%	6.0%	5.7%	5.8%	5.3%	5.8%	6.0%	5.7%	
3	Ameren Corporation (NYSE-AEE)	4.6%	4.9%	4.6%	4.7%	4.6%	4.9%	4.6%	7.0%	5.3%	4.6%	4.9%	4.6%	7.0%	5.3%	
4	American Electric Power Co. (NYSE-AEP)	6.3%	6.8%	6.3%	6.5%	6.3%	6.8%	6.3%	5.0%	6.1%	6.3%	6.8%	6.3%	5.0%	6.1%	
5	Avista Corporation (NYSE-AVA)	5.0%	NA	NA	5.0%	5.0%	NA	NA	5.0%	5.0%	5.0%	NA	NA	5.0%	5.0%	
6	Black Hills Corporation (NYSE-BKH)	3.5%	NA	NA	3.5%	3.5%	NA	NA	4.5%	4.0%						M&A
7	CMS Energy Corporation (NYSE-CMS)	6.8%	6.2%	6.8%	6.6%	6.8%	6.2%	6.8%	5.5%	6.3%	6.8%	6.2%	6.8%	5.5%	6.3%	
8	Consolidated Edison, Inc. (NYSE-ED)	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	3.0%	2.8%	2.7%	2.7%	2.7%	3.0%	2.8%	
9	Dominion Resources, Inc. (NYSE-D)	5.4%	6.3%	5.4%	5.7%	5.4%	6.3%	5.4%	8.0%	6.3%	5.4%	6.3%	5.4%	8.0%	6.3%	
10	Duke Energy Corporation (NYSE-DUK)	4.3%	4.7%	4.3%	4.4%	4.3%	4.7%	4.3%	5.0%	4.6%						M&A
11	Edison International (NYSE-EIX)	2.4%	4.7%	2.4%	3.2%	2.4%	4.7%	2.4%	3.0%	3.1%						Bankruptcy of EME
12	El Paso Electric Company (NYSE-EE)	7.0%	6.7%	NA	6.9%	7.0%	6.7%	NA	3.5%	5.7%	7.0%	6.7%	NA	3.5%	5.7%	
13	Empire District Electric Co. (NYSE-EDE)	3.0%	5.0%	NA	4.0%	3.0%	5.0%	NA	3.0%	3.7%	3.0%	5.0%	NA	3.0%	3.7%	
14	Entergy Corporation (NYSE-ETR)	-2.1%	-4.6%	-2.1%	-2.9%	-2.1%	-4.6%	-2.1%	0.0%	-2.2%						Negative Growth Rates
15	Eversource Energy (NYSE-ES)	6.3%	6.8%	6.2%	6.4%	6.3%	6.8%	6.2%	8.5%	7.0%	6.3%	6.8%	6.2%	8.5%	7.0%	
16	FirstEnergy Corporation (ASE-FE)	0.9%	NA	0.9%	0.9%	0.9%	NA	0.9%	7.0%	2.9%						Dividend Cut
17	Great Plains Energy Incorporated (NYSE-GXP)	6.4%	6.1%	6.4%	6.3%	6.4%	6.1%	6.4%	5.0%	6.0%	6.4%	6.1%	6.4%	5.0%	6.0%	
18	IDACORP, Inc. (NYSE-IDA)	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	1.0%	3.3%	4.0%	4.0%	4.0%	1.0%	3.3%	
19	MGE Energy, Inc. (NYSE-MGEE)	4.0%	NA	NA	4.0%	4.0%	NA	NA	7.0%	5.5%	4.0%	NA	NA	7.0%	5.5%	
20	NorthWestern Corporation (NYSE-NWE)	5.3%	5.0%	5.3%	5.2%	5.3%	5.0%	5.3%	6.5%	5.5%	5.3%	5.0%	5.3%	6.5%	5.5%	
21	OGE Energy Corp. (NYSE-OGE)	3.3%	5.0%	3.3%	3.9%	3.3%	5.0%	3.3%	3.0%	3.7%	3.3%	5.0%	3.3%	3.0%	3.7%	
22	Otter Tail Corporation (NDQ-OTTR)	6.0%	NA	NA	6.0%	6.0%	NA	NA	9.0%	7.5%	6.0%	NA	NA	9.0%	7.5%	
23	PG&E Corporation (NYSE-PCG)	5.9%	4.9%	5.9%	5.6%	5.9%	4.9%	5.9%	10.5%	6.8%						Financial implications of San Bruno
24	Pinnacle West Capital Corp. (NYSE-PNW)	5.4%	5.2%	5.4%	5.3%	5.4%	5.2%	5.4%	4.0%	5.0%	5.4%	5.2%	5.4%	4.0%	5.0%	
25	PNM Resources, Inc. (NYSE-PNM)	8.6%	8.0%	8.6%	8.4%	8.6%	8.0%	8.6%	9.0%	8.6%	8.6%	8.0%	8.6%	9.0%	8.6%	
26	Portland General Electric Company (NYSE-POR)	4.1%	4.3%	4.1%	4.2%	4.1%	4.3%	4.1%	6.0%	4.6%	4.1%	4.3%	4.1%	6.0%	4.6%	
27	SCANA Corporation (NYSE-SCG)	4.3%	4.2%	4.3%	4.3%	4.3%	4.2%	4.3%	4.5%	4.3%	4.3%	4.2%	4.3%	4.5%	4.3%	
28	Westar Energy, Inc. (NYSE-WR)	3.4%	3.9%	3.4%	3.6%	3.4%	3.9%	3.4%	6.0%	4.2%	3.4%	3.9%	3.4%	6.0%	4.2%	
29	Xcel Energy Inc. (NYSE-XEL)	4.7%	5.0%	4.7%	4.8%	4.7%	5.0%	4.7%	4.5%	4.7%	4.7%	5.0%	4.7%	4.5%	4.7%	
	Mean	4.6%	4.8%	4.5%	4.6%					4.9%					5.3%	
	Median	4.7%	5.0%	4.7%	4.8%					5.0%					5.5%	

Data Sources; www.reuters.com,www.zacks.com, http://quote.yahoo.com, October, 2015.

Exhibit AEB-R-12

BOND YIELD PLUS RISK PREMIUM

	[1] Average Authorized Electric ROE	[2] 30-year U.S. Treasury Bond	[3] Risk Premium
1992.1	12.29%	7.84%	4.46%
1992.2	11.86%	7.88%	3.97%
1992.3	11.89%	7.42%	4.48%
1992.4	12.23%	7.54%	4.69%
1993.1	11.91%	7.01%	4.90%
1993.2	11.64%	6.86%	4.78%
1993.3	11.08%	6.23%	4.86%
1993.4	11.09%	6.21%	4.88%
1994.1	11.19%	6.66%	4.53%
1994.2	11.29%	7.45%	3.84%
1994.3	12.75%	7.55%	5.20%
1994.4	11.25%	7.95%	3.30%
1995.1	11.90%	7.52%	4.37%
1995.2	11.36%	6.87%	4.50%
1995.3	11.28%	6.66%	4.61%
1995.4	11.67%	6.14%	5.53%
1996.1	12.25%	6.39%	5.86%
1996.2	12.06%	6.92%	5.14%
1996.3	11.00%	7.00%	4.00%
1996.4	11.40%	6.54%	4.86%
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	11.12%	6.04%	5.08%
1998.1	12.00%	5.89%	6.11%
1998.2	12.20%	5.79%	6.41%
1998.3	11.65%	5.32%	6.33%
1998.4	12.15%	5.11%	7.05%
1999.1	10.40%	5.43%	4.97%
1999.2	10.94%	5.82%	5.12%
1999.3	10.75%	6.07%	4.68%
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	11.50%	5.42%	6.08%
2001.2	10.75%	5.77%	4.98%
2001.3	10.76%	5.44%	5.32%
2001.4	12.69%	5.21%	7.48%
2002.1	10.10%	5.55%	4.55%
2002.2	11.57%	5.57%	6.00%
2002.3	11.25%	4.96%	6.29%
2003.1	11.49%	4.78%	6.72%
2003.2	11.58%	4.57%	7.01%
2003.3	9.75%	5.15%	4.60%
2003.4	11.28%	5.11%	6.17%
2004.1	11.00%	4.86%	6.14%
2004.2	10.67%	5.31%	5.36%
2004.3	11.00%	5.01%	5.99%
2004.4	11.18%	4.87%	6.30%
2005.1	10.65%	4.69%	5.96%
2005.2	10.00%	4.34%	5.66%
2005.3	11.63%	4.43%	7.19%
2005.4	10.65%	4.66%	5.99%
2006.1	10.38%	4.69%	5.68%
2006.2	10.60%	5.19%	5.41%
2006.3	10.05%	4.90%	5.15%
2006.4	10.49%	4.70%	5.79%
2007.1	10.40%	4.81%	5.59%
2007.2	10.31%	4.98%	5.32%
2007.3	10.00%	4.85%	5.15%
2007.4	10.12%	4.53%	5.60%
2008.1	10.04%	4.34%	5.70%
2008.2	10.57%	4.57%	6.00%
2008.3	10.52%	4.44%	6.08%
2008.4	10.50%	3.49%	7.01%
2009.1	10.44%	3.62%	6.82%
2009.2	10.56%	4.23%	6.33%
2009.3	10.25%	4.18%	6.07%
2009.4	10.41%	4.35%	6.06%
2010.1	10.37%	4.59%	5.78%
2010.2	9.97%	4.20%	5.77%
2010.3	10.05%	3.73%	6.32%
2010.4	10.27%	4.14%	6.13%
2011.1	9.90%	4.53%	5.37%
2011.2	10.12%	4.33%	5.79%
2011.3	10.66%	3.54%	7.11%
2011.4	10.47%	3.03%	7.44%
2012.1	10.25%	3.12%	7.13%
2012.2	9.98%	2.84%	7.15%
2012.3	9.69%	2.68%	7.01%
2012.4	10.13%	2.87%	7.26%
2013.1	9.98%	3.12%	6.86%
2013.3	9.45%	3.67%	5.77%
2013.4	9.64%	3.81%	5.83%
2014.1	9.68%	3.58%	6.10%
2014.2	9.93%	3.38%	6.55%
2014.3	9.62%	3.20%	6.42%
2014.4	9.76%	2.90%	6.85%
2015.1	9.50%	2.41%	7.09%
AVERAGE	10.89%	5.19%	5.70%
MEDIAN	10.76%	5.06%	5.78%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.809611
R Square	0.655469
Adjusted R Square	0.651554
Standard Error	0.005515
Observations	90

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.005091	0.005091	167.419934	0.000000
Residual	88	0.002676	0.000030		
Total	89	0.007767			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0857	0.002290	37.41	0.000000	0.081130	0.090232	0.081130	0.090232
30-year U.S. Treasury Bond	(0.5523)	0.042688	(12.94)	0.000000	(0.637176)	(0.467509)	(0.637176)	(0.467509)

	[7] U.S. Govt. 30-year Treasury	[8] Risk Premium	[9] ROE
Current 30-Day Average [4]	2.51%	7.18%	9.69%
Blue Chip Consensus Forecast (Q1 2015-Q2 2016) [5]	3.20%	6.80%	10.00%
Blue Chip Consensus Forecast (2016-2020) [6]	4.90%	5.86%	10.76%
AVERAGE			10.15%

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 0.085681 + (-0.552342 x Column [7])
[9] Equals Column [7] + Column [8]

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE – CHAIRMAN
BOB BURNS
BOB STUMP
TOM FORESE
ANDY TOBIN

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

EXHIBIT
UNSE-24
admitted

Rejoinder Testimony of

Ann E. Bulkley

on Behalf of

UNS Electric, Inc.

February 29, 2016

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EXHIBITS:

EXHIBIT AEB-1 ROBERT MEASE CAPM ANALYSIS
EXHIBIT AEB-2 AUTHORIZED ROE ANALYSIS - WOOLRIDGE PROXY GROUP

I. INTRODUCTION

Q. Please state your name and business address.

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

Q. On whose behalf are you submitting this testimony?

A. I am submitting this testimony on behalf of UNS Electric, Inc. ("UNS Electric" or the "Company").

Q. Did you previously submit testimony in this proceeding?

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

Q. What is the purpose of your Rebuttal Testimony?

A. The purpose of my Rebuttal Testimony is to respond to the cost of capital issues within the Surrebuttal Testimonies of Mr. Robert B. Mease on behalf of the Residential Utility Consumer Office ("RUCO") and Dr. J. Randall Woolridge on behalf of The Alliance for Solar Choice ("TASC"), collectively, the "Opposing ROE Witnesses").

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

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

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

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

- In Section II, I provide a summary and overview of my Rejoinder Testimony.
- In Section III, I respond to Mr. Mease's analyses and recommendations.
- In Section IV, I respond to Dr. Woolridge's analyses and recommendations.

II. RESPONSE TO THE REBUTTAL TESTIMONY OF RUCO WITNESS MEASE

Q. Please summarize the Surrebuttal Testimony of RUCO witness Mease.

A. Mr. Mease's Surrebuttal Testimony included updated DCF and CAPM analyses and a Comparable Earnings analysis. Based on the results of those analyses, Mr. Mease increased his recommended ROE from 8.35 percent to 9.13 percent. Mr. Mease accepts the Company's proposed capital structure which consists of 52.83 percent equity and 47.17 percent debt and the Company's 4.66 percent cost of debt. Separate from his updated analytical results, Mr. Mease states that RUCO would accept a 9.50 percent ROE assuming adoption of a certain revenue requirement..[1]

[1] Surrebuttal Testimony of Mr. Robert Mease, at 21-22.

Q. What is your response to Mr. Mease's recommended ROE?

A. Based on the results of the other analyses presented in my rebuttal testimony, I believe that a 9.50 percent ROE would represent the low end of the range of reasonable ROEs for UNS.

Q. Do you agree with the methodology used by Mr. Mease in the development of his updated Constant Growth DCF analysis?

A. Yes. Mr. Mease relies on 90-day average prices as of the end of January 2016 for a proxy group of twelve companies that is similar to the proxy group used in my rebuttal analysis. Mr. Mease relies on projected earnings per share growth rates from Value Line and Yahoo! Finance that are based on the analytical period that he relies on for historical prices. The range of results produced in this analysis is 8.33 percent to 10.12 percent, which overlaps the range of results presented in my Rebuttal Testimony using the Constant Growth DCF approach.

Q. Please summarize Mr. Mease's updated CAPM analysis.

A. Mr. Mease updated his CAPM analysis to reflect the proxy group change discussed previously. Mr. Mease presents two calculations of the historical Market Risk Premium ("MRP") in his CAPM analysis, the first is intended to be based on the geometric mean (Schedule RBM-6, page 1) and the section (Schedule RBM-6, page 2) based on the arithmetic mean. Mr. Mease relies on a risk free rate of 2.50 percent in his updated analysis. The beta used in his analysis is as published by Value Line. The results of these analyses are 7.07 percent and 6.84 percent respectively.

Q. Do you agree with Mr. Mease's updated CAPM analysis?

A. No, I do not. I believe that the use of a forward-looking estimate of the MRP is preferable to a historically calculated MRP for the reasons discussed in my Rebuttal Testimony. I

also do not agree with the use of the geometric mean in the analysis. This issue has also been addressed in my Rebuttal Testimony.

In addition to the differences in opinion on the methodologies, discussed previously, I also disagree with the specific calculations of the CAPM that are presented in Schedule 6 pages 1 and 2 of Mr. Mease's Surrebuttal Testimony Specifically, I disagree with the calculation of the historical MRP using the arithmetic and geometric means, and the current risk-free rate.

Mr. Mease calculates the MRP as the difference between the total return on large company stocks and the total return on long-term corporate bonds. There are two errors in this calculation. First, Mr. Mease has relied on the total bond return, not the income only portion of that return. As discussed in my rebuttal testimony, Morningstar, the publisher of the data relied on by Mr. Mease in his calculation of the MRP, states that to calculate the equity risk premium, it is necessary to deduct the income only return on bonds from the total stock return not the total return on the bond. Morningstar notes that the total return includes the capital appreciation, the income and the capital.

The second error is that Mr. Mease's calculation relies on the total return on corporate bonds, not on government bonds. Mr. Mease provides the CAPM formula in his Schedule RDM-6. In that formula he notes that the MRP is calculated as the market return (r_m) less the risk-free rate (r_f). Corporate bonds are not risk free assets. Traditionally, the income only return on government bonds have been used as a proxy for a risk-free asset.

Q. Are there other errors in the calculation of the MRP as presented in Schedule RDM-6?

A. I believe so. Schedule RDM-6, page 1 indicates that it is the CAPM using the geometric mean in the calculation of the MRP. Assuming that Mr. Mease has relied on Morningstar as the source of his data for this analysis, which is the common source for the calculation of the historical MRP, the geometric mean return on large company stocks is reported to be 10.1 percent. Mr. Mease's analysis relies on a return of 12.0 percent.

Q. Is the current risk free rate relied on by Mr. Mease consistent with the rate used in his Direct Testimony?

A. No. In his Direct Testimony, Mr. Mease uses the yield on the 30-year Treasury bonds, noting that the long-term bonds were specifically used since this matches the long-term perspective of the cost of equity analyses.[2] In his rebuttal testimony, Mr. Mease relies on the three-month average yield on the 20-year Treasury bonds, of 2.50 percent.[3] As of January 29, 2016, which is the time period relied on for his DCF analysis, the three-month average yield on 30-year Treasury bonds was approximately 2.95 percent.

Q. Have you adjusted Mr. Mease's analysis for these recommended changes?

A. Yes, I have. As shown in Exhibit AEB-1, updating Mr. Mease's analysis to correct the calculation of the historical MRP and using the current risk-free rate results in a range of returns of 6.90 percent to 8.38 percent.

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[2] Direct Testimony of Robert B. Mease, at 12.
[3] Yield curve provided by Robert B. Mease.

Q. Have you reviewed Mr. Mease's comparable earnings analysis?

A. Yes, I have.

Q. Do you typically rely on a comparable earnings analysis similar to what Mr. Mease has prepared?

A. No, I do not. The comparable earnings analysis prepared by Mr. Mease looks at the achieved return for the proxy companies over the period from 2002 through 2015 and estimates the return that will be achieved by those companies for three forward-looking time periods, 2016 and 2018 through 2020. Mr. Mease also calculates a return over the historical and projected time period.

The determination of the cost of equity in this proceeding is intended to be the return that is reasonable for UNS on a forward-looking basis. Therefore the historical actual returns over the last 14 years are not as significant as what investors are expecting for returns based on current and projected market conditions. However, as shown in Mr. Mease's schedule, the average return projected by AUS and Value Line for 2018-2020 is 9.50 percent.

Q. Do you agree with Mr. Mease's view on how the Commission should consider all analytical results presented in this case?

A. Mr. Mease states that no individual method provides an "exclusive foolproof formula for determining a fair return. In evaluating the cost of equity all relevant evidence should be used and weighted equally in order to minimize judgmental and measurement infirmities."[4]

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[4] Surrebuttal Testimony of Robert B. Mease, at 11.

While I agree that there is no foolproof formula, I believe it is the analyst's responsibility to consider the results of the individual methodologies to determine if each result is reasonable and would meet the standards established by *Hope* and *Bluefield*. Certain analyses presented to this Commission result in returns that are well below any authorized ROE for a vertically integrated utility over the past 35 years. I do not believe it is appropriate to rely on the mathematical average of the results of all methodologies especially if the results are outside of a range of reasonableness.

With respect to the analysis presented by Mr. Mease in his Surrebuttal Testimony, his CAPM results that range from 6.84 percent to 7.07 percent are 218-241 basis points below any authorized return for a vertically integrated utility in the last 35 years. Furthermore, this range is 206-229 basis points below Mr. Mease's recommended ROE of 9.13 percent and 243-266 basis points lower than the 9.50 percent ROE that Mr. Mease suggests RUCO would agree to along with other factors.[5] Based on these comparisons, I do not believe it would be appropriate to provide equal weight to these particular CAPM results or results that fall into a similar range that are produced using other methodologies, inputs and assumptions.

Q. Have other regulatory commissions rationalized ROE results as you suggest should be done?

A. Yes. The FERC has routinely identified a range of reasonableness for the ROE and has excluded results that are either above or below that range as being outliers. I would exclude these CAPM results on the same basis.

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[5] Surrebuttal Testimony of Robert B. Mease, at 21-22.

Q. Please summarize your conclusions with respect to Mr. Mease's analytical results.

A. Mr. Mease's Constant Growth DCF results produce a range of results between 8.33 percent and 10.12 percent, which is within the range established in my Rebuttal Testimony. The projected return estimates included in Mr. Mease's Comparable Earnings analysis estimates a range of earned returns for the individual proxy companies of between 7.50 percent and 12.5 percent for 2018 through 2020. The mean and median returns are 9.50 percent. While I do not necessarily agree with all of the methodologies relied on for the reasons discussed in my rebuttal and rejoinder testimony, the results of Mr. Mease's analysis support at least an ROE of 9.50 percent.

III. RESPONSE TO TASC WITNESS WOOLRIDGE

Q. Please summarize Dr. Woolridge's Surrebuttal Testimony.

A. Dr. Woolridge continues to support an ROE of 8.75 percent, which is 75 basis points below the ROE that has been agreed to by the Staff, RUCO and the Company.[6] As support for this position, Dr. Woolridge cites the current low interest rate environment and suggests that since analysts have not accurately predicted interest rate increase in recent years, forecasts should not be considered in setting the forward-looking ROE in this case. Dr. Woolridge acknowledges, however, that the average ROEs authorized by state regulatory commissions for electric utilities since 2012 have all been significantly higher than his recommendation.[7]

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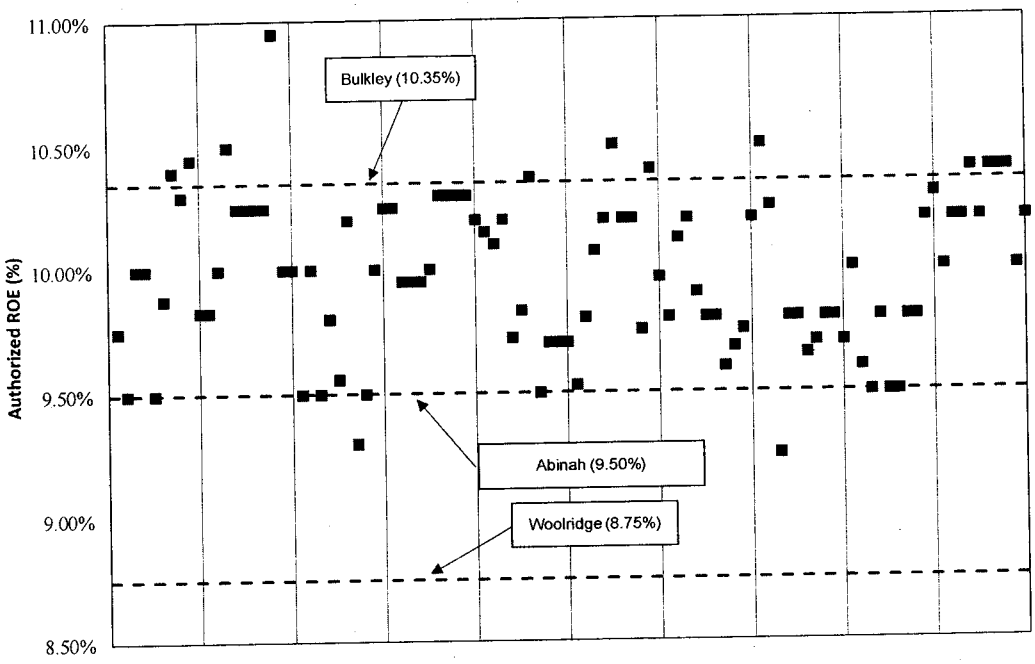
[6] Surrebuttal Testimony of J. Randall Woolridge, Ph.D., at 9.
[7] Surrebuttal Testimony of J. Randall Woolridge, Ph.D., at 4.

Q. What is your overall response to Dr. Woolridge's recommendation?

A. Dr. Woolridge presents unsubstantiated theories that allowed ROEs are lagging behind the decline in interest rates that has occurred in recent years, and that state Commissions have been reluctant to go below the 10.00 percent level. On this basis, Dr. Woolridge supports his ROE recommendation, even though it is 100 basis points lower than the average authorized ROE for integrated electric utilities in 2015 of 9.75 percent. While Dr. Woolridge argues that allowed ROEs have lagged behind capital market cost rates, meaning that they have been slow to reflect the lower interest rate environment, the average authorized ROE for electric utilities in 2015 actually increased since the filing of Dr. Woolridge's direct testimony. The average authorized ROE for vertically integrated electric utilities in the fourth quarter of 2015 was 9.86 percent. Woolridge offers no analysis or supporting documentation to demonstrate that UNS Electric has significantly lower risk than those electric utilities to justify a recommendation that is substantially lower than the average authorized ROE.

Chart 1 shows that authorized ROEs span a wide range over the period from 2012 through 2016. Dr. Woolridge's ROE recommendation of 8.75 percent is below that entire range. By comparison, my ROE recommendation of 10.35 percent is at the upper end of the range of ROE awards for vertically integrated electric utilities and the 9.50 percent ROE agreed upon by Staff, RUCO and the Company is below the average authorized ROE in 2015-2016.

Chart 1: ROE Decisions for Integrated Electric Utilities – 2012-2016



Contrary to Dr. Woolridge's position, capital market conditions do not suggest that allowed ROEs should be declining. Interest rates are expected to increase, credit spreads between government bonds and utility bonds have been widening, and volatility in equity markets has increased substantially since the Federal Reserve's decision in December 2015 to raise short-term interest rates, suggesting increased risk to equity holders.

Regarding Dr. Woolridge's critique of the ROE estimation methodologies relied on in developing my recommendation, Dr. Woolridge's Surrebuttal Testimony does not raise any issues that are materially different than those raised in his direct testimony. None of these points suggest that an ROE of 8.75 percent is warranted for UNS Electric.

IV. CAPITAL MARKET CONDITIONS

Q. What is Dr. Woolridge's view on current capital market conditions, interest rates and the effect of these factors on the return requirements of utility investors?

A. Dr. Woolridge testifies that interest rates have continued to decline despite continual forecasts of higher interest rates. As support for this position, Dr. Woolridge provides Figure 1, which charts the yield on 30-year Treasury bonds from 2009-2016. Dr. Woolridge's primary assertion with respect to interest rates is that forecasts of increasing interest rates have been wrong in the past; therefore, he argues that rather than rely on interest rate forecasts, it is more reasonable to rely on the current low interest rate environment as being representative of future conditions. In support of his position, Dr. Woolridge presents several studies that have reviewed economists' forecasts of Treasury bond yields over the period from 2010 through 2015.[8]

Q. Do you agree with Dr. Woolridge's view on capital market conditions and their effect on the return requirements of utility investors?

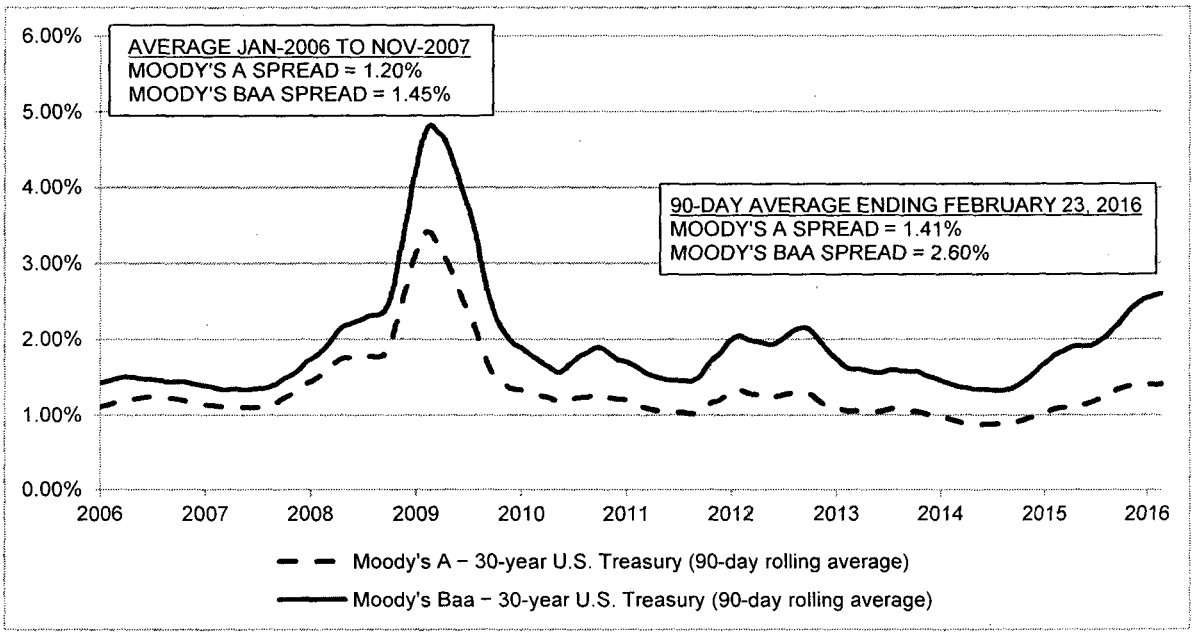
A. No, I do not. I will readily acknowledge that economists and others have struggled to accurately predict the path of interest rates over the past several years. However, this period has included the most severe recessionary period experienced in recent times followed by a slow and uncertain economic recovery. The combination of Federal Reserve market intervention (e.g., quantitative easing) and the uncertain path of post-Great Recession economic recovery have made such predictions challenging. In my view, however, this does not render interest rate forecasts meaningless to investors. I am not aware of any market expert or investor that would assume, as Dr. Woolridge does, that it is reasonable that current interest rates on government bonds, which remain near

[8] Surrebuttal Testimony of J. Randall Woolridge, Ph.D., at 11.

25 year lows, will be the rates experienced in the marketplace in the future.[9] This logic belies the basic upward sloping shape of the Treasury yield curve, as well as the recent policy statements of the Federal Reserve.

In addition, Dr. Woolridge entirely ignores the fact that yields on corporate and utility bonds have been steadily increasing, and that credit spreads between government bonds and corporate bonds are higher than they were immediately prior to the 2007-2009 financial crisis. As discussed in my rebuttal testimony, these elevated credit spreads are an indication of investor risk aversion that should not be dismissed. I have updated Chart 2 from my rebuttal testimony through February 23, 2016. As shown on the chart, average spreads between A-rated and Baa-rated utility bonds and government bonds have continued to increase since the filing of my rebuttal testimony. This evidence contradicts Dr. Woolridge's view that capital costs for utilities are declining.

Chart 2: Credit Spreads for Moody's A- and Baa-rated Utility Bonds

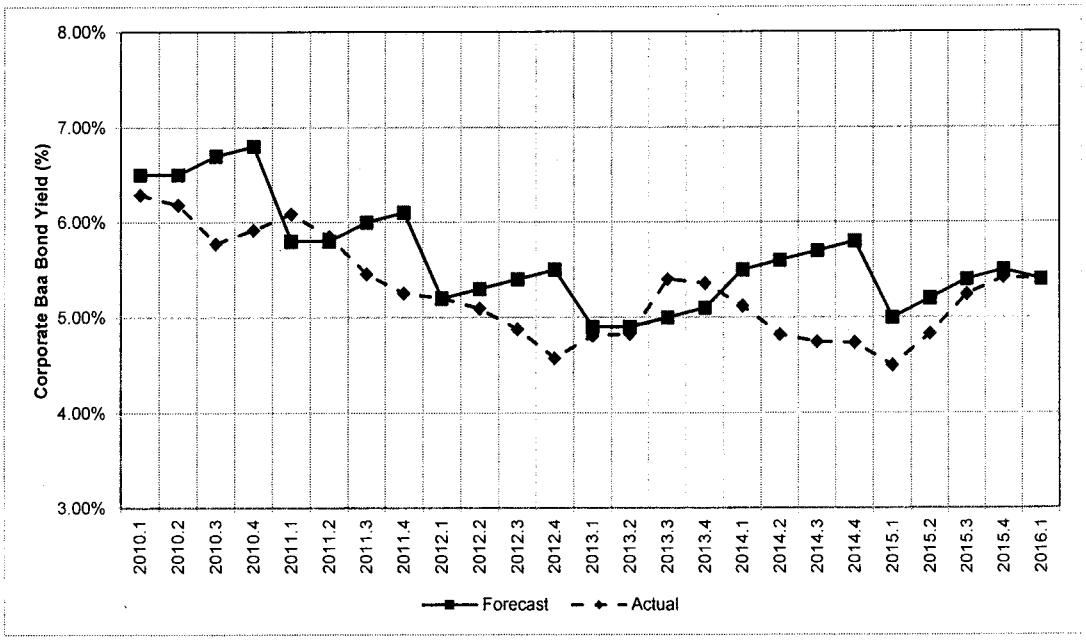


[9] Surrebuttal Testimony of J. Randall Woolridge, Ph.D., at 15.

Q. What is your response to Dr. Woolridge's concern about the ability of forecasters to accurately predict interest rates?

A. Dr. Woolridge has focused entirely on government bond yields, which are heavily influenced by the monetary policy of the Federal Reserve. As shown in Figure 1, however, projections of Baa-rated corporate bond yields (which are controlled by market forces) from Blue Chip Financial Forecasts for the period 2010 through 2016 have been more accurate than projections of government bond yields (which are subject to Federal intervention).

Chart 3: Corporate Bond Yield Projections and Actual Yields – 2010 - 2016



Corporate bond yields are more closely tied to equity cost rates. The increase in yields on corporate and utility bonds suggests that equity costs are also higher because there is a direct connection between equity costs and yields on corporate and utility bonds. It is for this reason that, in developing an ROE adjustment formula, the California Public Utilities Commission ("PUC") relies on the change in the Moody's utility bond yield, because it is

more closely tied to changes in equity costs than are government bonds. The California PUC explains its rationale as follows:

> The purpose of an interest rate benchmark is to gauge changes in interest rates that also indicate changes in equity costs of utilities. U.S. Treasuries are more sensitive to economic changes and risks in the international capital markets than utility bonds because they are bought and sold globally. However, U.S. utility bonds are generally affected less than Treasuries as a result of major shifts of international capital because a majority of U.S. utility bonds are traded within the U.S.
>
> Consistent with our use of utility bond interest rates in ROE, PBR, and MICAM proceedings and desire to use an index that more likely correlates and moves with utility industry risk, utility bonds should be adopted for the CCM [cost of capital mechanism] index.[10]

Q. What is your conclusion regarding Dr. Woolridge's recommendation to rely on current interest rates rather than forward-looking estimates of interest rates?

A. The estimation of the ROE is a forward-looking concept. Therefore, it is reasonable and appropriate to consider what investors believe market conditions will be in the future. Investors, not just economists and market forecasters, are expecting that interest rates will rise. This factor must be accounted for in estimating the ROE for UNS Electric.

Q. Please summarize Dr. Woolridge's testimony with respect to the market reaction to the Federal Reserve's announcement of a 25 basis point increase in the Fed Funds rate in December 2015.

A. On page 13 of his Surrebuttal Testimony, Dr. Woolridge presents a chart of yields on U.S. Treasury bonds on December 16, 2015, which is the day when the Federal Reserve announced its decision to raise short-term interest rates by 25 basis points. On pages 14-

[10] Public Utilities Commission of the State of California, Decision 08-05-035, May 29, 2008 at 12-13.

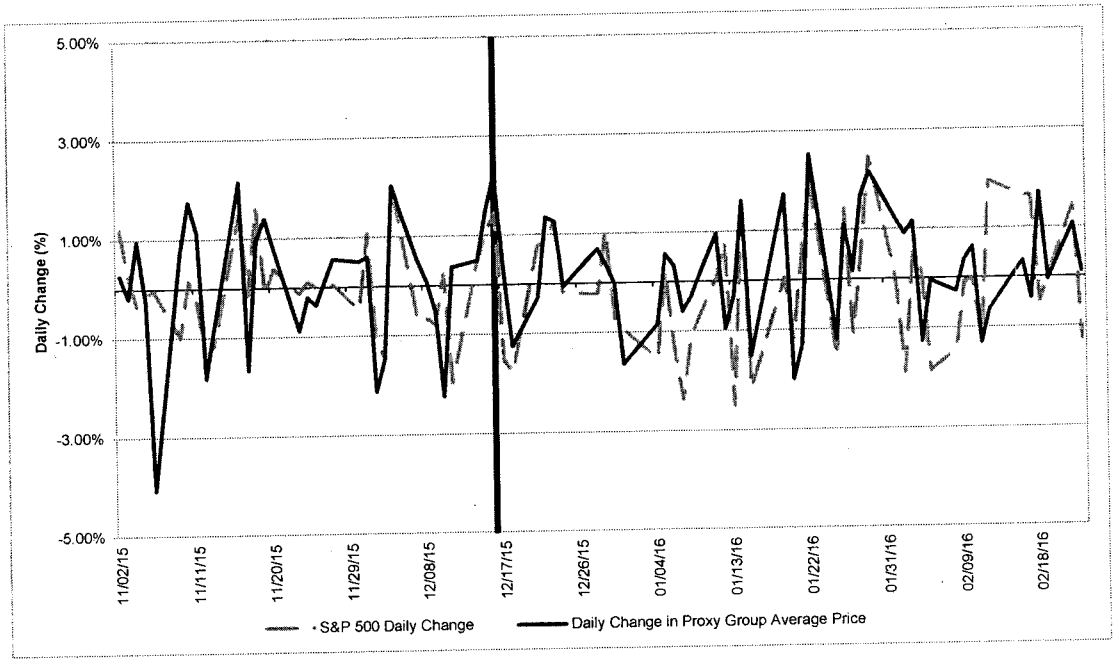
15, Dr. Woolridge testifies that the Dow Jones Utility Index has risen by 8.0 percent since the FOMC announcement, while the S&P 500 has declined by 4.0 percent.

Q. Has Dr. Woolridge considered the recent volatility in financial markets, and the implications for the cost of capital?

A. No, he has not. Based on Figure 8 in Dr. Woolridge's Surrebuttal Testimony, he appears to believe that the two hour time span following the FOMC's announcement of its decision to increase the Fed Funds rate by 25 basis points is somehow indicative of investor's long-term sentiment. However, Dr. Woolridge has ignored the fact that market volatility has been significant in the last several months. Volatility is another sign of investor risk aversion.

I have conducted an analysis of the volatility in the share prices of the companies in my proxy group for the period from November 2, 2015 through February 23, 2016. As shown in Chart 4, the share price volatility of my proxy group companies has been similar to the volatility of the S&P 500 during this period.

Chart 4: S&P 500 and Proxy Group Average Price Volatility



It is not surprising that increased volatility (i.e., risk) in equity markets, including utility stocks, would drive investors toward lower-risk alternatives such as Treasury bonds in the short-term. Increased volatility in equity markets demonstrates an increase in the risk for shareholders, which results in a higher cost of equity, not a lower cost of equity as suggested by Dr. Woolridge.

Q. Dr. Woolridge states that the purpose of your comparison of forecasted economic indicators on pages 23-24 of your rebuttal testimony was to support Mr. Abinah's claim that the 9.50 percent ROE provided in the 2013 settlement is reflective of the current economic environment. What is your response?

A. Dr. Woolridge apparently misunderstood the analysis in my rebuttal testimony. The intention of that analysis was to demonstrate the difference in forecasted economic conditions between the 2009 and 2012 cases and 2015, in order to support my ROE recommendation. As stated in my rebuttal testimony, based on that analysis, my

conclusions were that projected unemployment rates have declined substantially from 9.9 percent in November 2009 to 4.8 percent in November 2015. Similarly, projected growth in disposable personal income has increased from 1.4 percent in November 2009 to 2.7 percent in November 2015, as U.S. consumers are feeling more confident about prospects for employment, wage gains and economic growth. Forecasted real GDP growth has remained steady since 2009 as the economic recovery has been weaker than after most recessions, while the projected inflation rate is slightly lower than in November 2009, which allowed the Federal Reserve to maintain its "highly accommodative" monetary stance for longer than expected.

Q. Do you agree with Dr. Woolridge that historical trends in GDP growth, unemployment, and inflation suggest that capital costs have declined?

A. No, I do not. On pages 8 and 9 of his Surrebuttal Testimony, Dr. Woolridge presents three charts showing historical GDP growth, the unemployment rate, and the annual inflation rate from 2006 through 2015. As discussed previously with regard to interest rates, the use of historical economic data from this time period was characterized by one of the most severe recessions in U.S. history, followed by an uncommonly slow and uncertain economic recovery, which makes a review of historical data from this period difficult to interpret as the expectations of future market conditions. The highly accommodative monetary policy of the Federal Reserve during much of this period has distorted the level of government bond yields, even as the economy has slowly recovered and unemployment has dropped below 5.0 percent. The FOMC's decision to increase short-term interest rates in December 2015 suggests that they do not agree with Dr. Woolridge that capital costs should remain at historic lows, given the outlook for economic growth and stronger employment trends.

Q. Please summarize your position regarding how the Commission should consider market conditions in establishing a reasonable ROE for UNS Electric.

A. The ROE that is set in this case is intended to be a forward-looking ROE. Dr. Woolridge suggests ignoring projected interest rates because he argues that forecasters cannot predict the future with certainty. Instead, Dr. Woolridge suggests that the Commission should assume that interest rates on government bonds will not change from current levels, even though those interest rates are near 25 year lows and are heavily influenced by the highly accommodative monetary policy of the Federal Reserve. In my view, given current market conditions and analysts' expectations that interest rates will not remain at the currently low levels as the economy continues to recover from the severe recession, it is reasonable to consider the effect of rising interest rates in developing a forward-looking estimate of the cost of equity.

V. RESPONSE TO WOOLRIDGE'S CRITIQUE OF BULKLEY ROE ESTIMATION METHODOLOGIES

Q. Please summarize the issues that are discussed in this section.

A. In this section of my rejoinder testimony, I respond to Dr. Woolridge's critique of (1) the growth rates used in my constant growth DCF model, (2) the long-term GDP growth rate in my multi-stage DCF model, (3) various inputs and assumptions in my CAPM analysis, and (4) the validity of my Bond Yield plus Risk Premium analysis.

Q. What is Dr. Woolridge's position with respect to the earnings growth forecasts that you relied on in your constant growth DCF analysis?

A. Dr. Woolridge criticizes my constant growth DCF analysis for relying on projected EPS growth rates, stating that these growth rates are biased upward. Dr. Woolridge cites a

2010 McKinsey study to support his view that analyst bias still exists. Despite his belief that EPS growth rates are biased, Dr. Woolridge acknowledges that in choosing the growth rate used in his DCF model, he relied primarily on the EPS growth rates for his proxy group.[11]

Q. What is your response to Dr. Woolridge's use of growth rates other than forecasted EPS growth rates in his constant growth DCF analysis?

A. Dr. Woolridge also presented other growth rates, such as 5-year and 10-year historical growth rates in EPS and DPS as reported by Value Line, although he has either not relied on these growth rates or given them less weight in his DCF analysis. Since the ROE that is to be established in this proceeding is forward-looking, I believe it is more appropriate to rely on the projected growth rates. Furthermore, as discussed previously with respect to interest rates, my concern with the use of this data is that the time period covered by these historical growth rates represents the severe recessionary period of 2007-2009 and the post-recessionary period, which has been viewed by analysts as an unusually slow recovery. I do not believe it is reasonable to expect that future growth rates will reflect this particular historical period.

Q. What is your response to Dr. Woolridge's opinion that analyst growth rates are overly optimistic?

A. With regard to the 2010 McKinsey study, my response is that the McKinsey study does not break out the reported results by industry, so it is not possible to conclude whether the observed analyst bias pertains specifically to regulated electric and gas utilities. However, Exhibit JRW-4, page 2, of Dr. Woolridge's Direct Testimony shows that earnings predictability and stock price stability are high for the companies in both the

[11] Surrebuttal Testimony of J. Randall Woolridge, Ph.D., at 18.

Woolridge and Bulkley proxy groups. On the one hand, Dr. Woolridge is arguing that regulated utilities are low risk compared to other industry groups because they have low Beta coefficients and high earnings predictability and stock price stability. On the other hand, Dr. Woolridge is concerned that utilities' earnings growth rates are not predictable and that analyst growth rates are overly optimistic. It is difficult to reconcile these two positions.

The McKinsey study also states that the size of the forecast error tends to decline when economic growth accelerates and increase as economic growth slows. This suggests that, as the U.S. economy has recovered from the Great Recession, the size of any forecast error should be declining. Finally, Wall Street analysts are required to certify that their analyses and recommendations are not related, either directly or indirectly, to their compensation.[12] In light of restrictions imposed by the October 2003 Global Settlement, it is unclear how or why utility analysts' estimates would continue to be biased. That settlement required financial institutions to insulate investment banking from analysis, prohibited analysts from participating in "road shows", and required the settling financial institutions to fund independent third-party research.[13]

Q. In addition to the information provided in your rebuttal testimony, are you aware of any additional articles on analyst bias?

A. Yes, I am. According to Zacks Investment Research, a reputable source of consensus growth rate forecasts, brokerage analysts are "expected to be to objective experts for the

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12 See, http://www.sec.gov/rules/final/33-8193. {Regulation AC]

13 The 2002 Global Financial Settlement resolved an investigation by the U.S. Securities and Exchange Commission and the New York Attorney General's Office of a number of investment banks related to concerns about conflicts of interest that might influence the independence of investment research provided by equity analysts.

industries they cover."[14] With regard to guidance provided by companies to brokerage analysts, Zacks writes:

> It is not in the best interest of corporate executives to share the most optimistic projections with brokerage analysts, however. A large percentage of executive compensation comes from company stock and stock option plans. Executives realize that if their company reports earnings that are below analysts' forecasts, almost without exception, the stock price will tumble. This in turn costs them money. Therefore, it is more advantageous for executives to provide brokerage analysts with conservative earnings estimates.[15]

With respect to analyst's incentive to provide overly optimistic earnings forecasts, Zacks observes:

> Clients will only act on a brokerage analyst's recommendation if they think the recommendation will help them make money. The more money a firm's clients make from a particular analyst's recommendations, the more valuable the analyst is to the firm. Since the analysts issue far more "buy" recommendations than "sell" recommendations, they want to avoid making earnings forecasts that are overly optimistic. The incentive for issuing conservative earnings estimates is that the company has a better chance of reporting earnings that exceed forecasts. In turns, clients will be happy to see the stock's price rise. Conversely, there is no incentive to issue an earnings forecast that is overly optimistic.[16]

Finally, in terms of the issue of reported earnings vs. forecasted earnings, Zacks observes:

> Over 10 years ago, only about 50% of companies met or exceeded earnings estimates every quarter. Now that number has moved to 80% as corporate executives and brokerage analysts have wised up to the importance of creating conservative earnings estimates.[17]

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14 Source: http://www.zacks.com/help/zrank-guide.php?p=3
15 Ibid.
16 Ibid.
17 Ibid.

Q. What is the long-term GDP growth rate that you relied on in your Multi-Stage DCF analysis?

A. As discussed in my rebuttal testimony, I relied on a long-term GDP growth rate of 5.4 percent.[18] This long-term growth rate is applied beginning in year 11 and continuing through year 200 of the multi-stage DCF analysis.

Q. Please summarize Dr. Woolridge's response to the GDP growth rate you relied on in your Multi-Stage DCF analysis.

A. Dr. Woolridge again refers to historical five and ten-year measures of growth in earnings and dividends for utility companies, the majority of which include the Great Recession and post-recessionary period, and concludes that these growth rates are substantially lower than the GDP growth rate I have relied on as a measure of the long-term projected growth. Dr. Woolridge states that I have not provided any theoretical or empirical support for this growth rate.[19] Finally, Dr. Woolridge states that I have ignored projected long-term GDP growth rates from government agencies in favor of historical data.

Q. What is your response to Dr. Woolridge on the development of the long-term GDP growth rate used in your analysis?

A. Dr. Woolridge tries to reconcile the forward-looking long-term growth rate provided by government agencies with the 5-10 year historical growth in earnings and dividends for utilities. However, as discussed previously, the 5-10 year historical growth is reflective of a very severe recessionary period, followed by a very slow recovery from that recession. As such, it is not reasonable to suggest that the long-term GDP growth rate in

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[18] The Surrebuttal Testimony of J. Randall Woolridge, Ph.D., incorrectly references this growth rate as being 540% (p. 21).

[19] Surrebuttal Testimony of J. Randall Woolridge, Ph.D., at 21.

the multi-stage DCF model, which will be applied more than ten years after that severe recession, should be in line with growth rates during that historical period. In summary, while Dr. Woolridge criticizes the long-term nominal GDP growth rate used in my multi-stage DCF analysis for not being consistent with the most recent economic downturn, my approach takes into consideration the real GDP growth rate during all the economic cycles since 1929 and the projected long-term inflation rate, consistent with the approach discussed by market analysts such as Morningstar.[20]

Q. Dr. Woolridge states that your long-term GDP growth rate is not supported by any empirical studies. What is your response?

A. The use of GDP growth either for the final stage of a multi-stage DCF analysis or for determining a "blended growth rate" is common practice among practitioners and accepted by regulators. The logic for this practice is that over the long run, a utility's revenues and earnings will grow at about the same pace as the general economy. Dr. Morin cites this logic in his book on regulatory finance:

> One way to account for the two stages of growth is to modify the single-stage DCF model by specifying the growth rate as a weighted average of short-term and long-term growth rates. The blended growth rate is calculated as a weighted average giving two-thirds weight to the analyst's five-year growth projections (Zacks, IBES, etc.) and one-third to historical long-term growth of the economy as a whole and/or the long-range projections of growth in Gross Domestic Product (GDP) projected for the very long term. FERC has adopted such a method in the past for determining the return on equity for gas and oil utilities.[21]

[20] Rebuttal Testimony of Ms. Bulkley, at 57.

[21] Roger A. Morin, Ph.D., *New Regulatory Finance*, Public Utility Reports, Inc., 2006, p. 309.

Q. Has the FERC recently revised its DCF methodology for electric utilities?

A. Yes In its recent Order No. 531, the FERC gave considerable attention to this matter as it relates to long term growth rates for electric utilities. It ultimately concluded:

> Therefore, in this proceeding, and in future public utility cases, the Commission will adopt the same two-step DCF methodology used in natural gas and oil pipeline cases. In other words, there will be a single, six-month average dividend yield for each company in the proxy group. More importantly, the estimate of the dividend growth rate for each company in the proxy group will now include a short-term projection of dividend growth (with a two-thirds weight) and a long-term projection of dividend growth (with a one-third weight). The short-term growth estimate will be based on the five-year projections reported by IBES (or a comparable source). *Given the absence of an electric industry-specific long-term growth projection that reasonably reflects investor expectations, the long-term growth estimate will be based on an average of the GDP growth rates that have been relied on in gas and oil pipeline cases*. [footnotes excluded, FERC Order 531 at 39.]

This reinforces both the logic and precedent for utilizing GDP as a proxy for long-term growth rates in the multi-stage DCF model.

Q. Dr. Woolridge continues to criticize the market risk premium used in your CAPM analysis because it is derived from analysts' EPS growth rates for the companies in the S&P 500, which he believes are overly-optimistic and upwardly-biased. What is your response?

A. Dr. Woolridge does not offer any new arguments in his Surrebuttal Testimony that I have not already responded to in my rebuttal testimony. As stated in my rebuttal testimony, according to Dr. Woolridge: "The MRP is the difference in the expected total return between investing in equities and investing in 'safe' fixed income assets, such as long-

term government bonds."[22] Dr. Woolridge states that the expected total return for the market is often measured by reference to the S&P 500.[23] This is consistent with the approach I have used to estimate the forward-looking MRP in my CAPM analysis. Therefore, I continue to believe that the results of my CAPM analysis are a reliable indicator of equity cost rates for electric utility companies such as UNS Electric.

Q. Please comment on Dr. Woolridge's concern that your Bond Yield Plus Risk Premium analysis uses the historical risk premium and applies it to forecasted Treasury bond yields.

A. My Bond Yield Plus Risk Premium analysis is based on a regression analysis that establishes the relationship between authorized ROEs for electric utilities and corresponding Treasury bond yields at the time of the ROE award. Based on the regression model, it is possible to determine what a reasonable ROE would be at a given interest rate. My analysis presents the results based on both current Treasury bond yields and near-term and long-term forecasts. The 9.87 percent that Dr. Woolridge references from the updated analysis presented in my rebuttal testimony is based on a 30-day average of the actual yield on 30-year Treasury bonds as of November 30, 2015. Even that result, which is based on currently low Treasury bond yields, is 112 basis points higher than Dr. Woolridge's ROE recommendation of 8.75 percent.

Q. Dr. Woolridge states that the trend and norm for authorized ROEs nationally is below 10.0 percent. Do you agree?

A. I do not. As shown in Chart 1, there have been 108 rate cases involving integrated electric utilities from January 2012 through February 2016 where the allowed ROE has

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22 Direct Testimony of J. Randall Woolridge, Ph.D., at D-20.
23 Ibid.

been specified in the decision. Slightly more than half (i.e., 51 percent) of those 108 decisions has resulted in an allowed ROE of 10.0 percent or higher. Consequently, I conclude that the majority of ROE awards for integrated electric utilities since 2012 have been above 10.0 percent.

I also researched the current authorized ROE for the companies in Dr. Woolridge's proxy group. As shown in Attachment AEB-2, the average ROE award for these companies (including both electric and natural gas) has been 10.00 percent. In computing this average, I eliminated any decisions that did not specify the authorized ROE and any decisions that were issued prior to 2010.

Q. Does this conclude your rejoinder testimony?

A. Yes, it does.

Exhibit AEB-1

Robert Mease CAPM Analysis
Corrections

Schedule RDM-6, page 1- As filed
Geometric Mean

Ticker	Rf rate	Beta	Rm	Rf	Expected Return
ALE	2.50%	0.80	12.00%	6.10%	7.22%
AEP	2.50%	0.70	12.00%	6.10%	6.63%
EE	2.50%	0.75	12.00%	6.10%	6.93%
EDE	2.50%	0.70	12.00%	6.10%	6.63%
ES	2.50%	0.75	12.00%	6.10%	6.93%
GXP	2.50%	0.85	12.00%	6.10%	7.52%
IDA	2.50%	0.80	12.00%	6.10%	7.22%
OTTR	2.50%	0.85	12.00%	6.10%	7.52%
PNW	2.50%	0.75	12.00%	6.10%	6.93%
PNM	2.50%	0.80	12.00%	6.10%	7.22%
POR	2.50%	0.80	12.00%	6.10%	7.22%
WR	2.50%	0.75	12.00%	6.10%	6.93%
			Mean		7.07%

Schedule RDM-6, page 1 -Corrected
Geometric Mean

Ticker	Rf rate	Beta	Rm	Rf	Expected Return
ALE	2.95%	0.80	10.1%	5.00%	7.03%
AEP	2.95%	0.70	10.1%	5.00%	6.52%
EE	2.95%	0.75	10.1%	5.00%	6.78%
EDE	2.95%	0.70	10.1%	5.00%	6.52%
ES	2.95%	0.75	10.1%	5.00%	6.78%
GXP	2.95%	0.85	10.1%	5.00%	7.29%
IDA	2.95%	0.80	10.1%	5.00%	7.03%
OTTR	2.95%	0.85	10.1%	5.00%	7.29%
PNW	2.95%	0.75	10.1%	5.00%	6.78%
PNM	2.95%	0.80	10.1%	5.00%	7.03%
POR	2.95%	0.80	10.1%	5.00%	7.03%
WR	2.95%	0.75	10.1%	5.00%	6.78%
				Mean	6.90%

Schedule RDM-6, page 2- As filed
Arithmetic Mean

Ticker	Rf rate	Beta	Rm	Rf	Expected Return
ALE	2.50%	0.80	12.00%	6.40%	6.98%
AEP	2.50%	0.70	12.00%	6.40%	6.42%
EE	2.50%	0.75	12.00%	6.40%	6.70%
EDE	2.50%	0.70	12.00%	6.40%	6.42%
ES	2.50%	0.75	12.00%	6.40%	6.70%
GXP	2.50%	0.85	12.00%	6.40%	7.26%
IDA	2.50%	0.80	12.00%	6.40%	6.98%
OTTR	2.50%	0.85	12.00%	6.40%	7.26%
PNW	2.50%	0.75	12.00%	6.40%	6.70%
PNM	2.50%	0.80	12.00%	6.40%	6.98%
POR	2.50%	0.80	12.00%	6.40%	6.98%
WR	2.50%	0.75	12.00%	6.40%	6.70%
			Mean		6.84%

Schedule RDM-6, page 2- Corrected
Arithmetic Mean

Ticker	Rf rate	Beta	Rm	Rf	Expected Return
ALE	2.95%	0.80	12.10%	5.10%	8.55%
AEP	2.95%	0.70	12.10%	5.10%	7.85%
EE	2.95%	0.75	12.10%	5.10%	8.20%
EDE	2.95%	0.70	12.10%	5.10%	7.85%
ES	2.95%	0.75	12.10%	5.10%	8.20%
GXP	2.95%	0.85	12.10%	5.10%	8.90%
IDA	2.95%	0.80	12.10%	5.10%	8.55%
OTTR	2.95%	0.85	12.10%	5.10%	8.90%
PNW	2.95%	0.75	12.10%	5.10%	8.20%
PNM	2.95%	0.80	12.10%	5.10%	8.55%
POR	2.95%	0.80	12.10%	5.10%	8.55%
WR	2.95%	0.75	12.10%	5.10%	8.20%
				Mean	8.38%

Exhibit AEB-2

AUTHORIZED RETURN ON EQUITY ANALYSIS - WOOLRIDGE PROXY GROUP
AUTHORIZED RETURN ON EQUITY

Woolridge Electric Proxy Group Company	Ticker	Authorized Return on Equity
ALLETE, Inc.	ALE	10.38%
Alliant Energy Corporation	LNT	10.31%
Ameren Corporation	AEE	9.42%
American Electric Power Company, Inc.	AEP	9.97%
Avista Corporation	AVA	10.06%
Black Hills Corporation	BKH	9.93%
CMS Energy Corporation	CMS	10.30%
Consolidated Edison, Inc.	ED	9.21%
Dominion Resources, Inc.	D	10.20%
Duke Energy Corporation	DUK	10.06%
Edison International	EIX	10.45%
El Paso Electric Company	EE	
Empire District Electric Company	EDE	
Entergy Corporation	ETR	9.93%
Eversource Energy	ES	9.41%
FirstEnergy Corporation	FE	9.75%
Great Plains Energy Inc.	GXP	9.50%
IDACORP, Inc.	IDA	9.90%
MGE Energy, Inc.	MGEE	10.20%
NorthWestern Corporation	NWE	10.03%
OGE Energy Corporation	OGE	10.08%
Otter Tail Corporation	OTTR	10.74%
PG&E Corporation	PCG	10.40%
Pinnacle West Capital Corporation	PNW	10.00%
PNM Resources, Inc.	PNM	10.07%
Portland General Electric Company	POR	9.60%
SCANA Corporation	SCG	10.25%
Westar Energy, Inc.	WR	
Xcel Energy Inc.	XEL	9.86%
MEAN		10.00%
LOW		9.21%
HIGH		10.74%

AUTHORIZED RETURN ON EQUITY - UTILITY OPERATING COMPANIES

Company Name	Ticker	Type	States of Operation	Year Completed	Docket No.	Authorized Return on Equity
ALLETE (Minnesota Power)	ALE	Electric	Minnesota	2010	D-E-015/GR-09-1151	10.38%
Interstate Power & Light Co.	LNT	Electric	Iowa	2010	D-RPU-2010-0001	10.44%
Interstate Power & Light Co.	LNT	Natural Gas	Iowa	2012	D-RPU-2012-0002	10.00%
Wisconsin Power and Light Co	LNT	Electric	Wisconsin	2014	D-6680-UR-119 (Elec)	10.40%
Wisconsin Power and Light Co	LNT	Natural Gas	Wisconsin	2014	D-6680-UR-119 (Gas)	10.40%
Ameren Illinois	AEE	Electric	Illinois	2015	D-15-0305	9.14%
Ameren Illinois	AEE	Natural Gas	Illinois	2015	D-15-0142	9.60%
Union Electric Co.	AEE	Electric	Missouri	2015	C-ER-2014-0258	9.53%
Appalachian Power Co.	AEP	Electric	Virginia	2014	C-PUE-2014-00026	9.70%
Appalachian Power Co.	AEP	Electric	West Virginia	2015	C-14-1152-E-42T	9.75%
Indiana Michigan Power Co.	AEP	Electric	Indiana	2013	Ca-44075	10.20%
Indiana Michigan Power Co.	AEP	Electric	Michigan	2012	C-U-16801	10.20%
Ohio Power Co.	AEP	Electric	Ohio	2011	C-11-0352-EL-AIR	10.30%
Southwestern Electric Power Co	AEP	Electric	Louisiana	2013	D-U-32220	10.00%
Southwestern Electric Power Co	AEP	Electric	Texas	2013	D-40443	9.65%
Avista Corp.	AVA	Electric	Idaho	2015	C-AVU-E-15-05	9.50%
Avista Corp.	AVA	Natural Gas	Idaho	2015	C-AVU-G-15-01	9.50%
Avista Corp.	AVA	Natural Gas	Oregon	2015	D-UG-284	9.50%
Avista Corp.	AVA	Electric	Washington	2016	D-UE-150204	9.50%
Avista Corp.	AVA	Natural Gas	Washington	2016	D-UG-150205	9.50%
Alaska Electric Light Power	AVA	Electric	Alaska	2011	D-U-10-029	12.88%
Black Hills Colorado Electric	BKH	Electric	Colorado	2014	D-14AL-0393E	9.83%
Black Hills Nebraska Gas	BKH	Natural Gas	Nebraska	2010	D-NG-0061	10.10%
Cheyenne Light Fuel Power Co.	BKH	Electric	Wyoming	2014	D-20003-132-ER-13	9.90%
Cheyenne Light Fuel Power Co.	BKH	Natural Gas	Wyoming	2014	D-30005-182-GR-13	9.90%
Consumers Energy Co.	CMS	Electric	Michigan	2015	C-U-17735	10.30%
Consumers Energy Co.	CMS	Natural Gas	Michigan	2015	C-U-17643	10.30%
Consolidated Edison Co. of NY	ED	Electric	New York	2015	C-15-E-0050/C-13-E-0030 (Ext)	9.00%
Consolidated Edison Co. of NY	ED	Natural Gas	New York	2014	C-13-G-0031	9.30%
Orange & Rockland Utlts Inc.	ED	Electric	New York	2015	C-14-E-0493	9.00%
Orange & Rockland Utlts Inc.	ED	Natural Gas	New York	2015	C-14-G-0494	9.00%
Rockland Electric Company	ED	Electric	New Jersey	2014	D-ER-13111135	9.75%
Virginia Electric & Power Co.	D	Electric	North Carolina	2012	D-E-22, Sub 479	10.20%
Duke Energy Carolinas LLC	DUK	Electric	North Carolina	2013	D-E-7, Sub 1026	10.20%
Duke Energy Carolinas LLC	DUK	Electric	South Carolina	2013	D-2013-59-E	10.20%
Duke Energy Ohio Inc.	DUK	Electric	Ohio	2013	C-12-1682-EL-AIR	9.84%
Duke Energy Ohio Inc.	DUK	Natural Gas	Ohio	2013	C-12-1685-GA-AIR	9.84%
Duke Energy Progress LLC	DUK	Electric	North Carolina	2013	D-E-2, Sub 1023	10.20%
Southern California Edison Co.	EIX	Electric	California	2012	Ap-12-04-015	10.45%
Entergy Arkansas Inc.	ETR	Electric	Arkansas	2016	D-15-015-U	9.75%
Entergy Gulf States LA LLC	ETR	Electric	Louisiana	2013	D-U-32707	9.95%
Entergy Louisiana LLC	ETR	Electric	Louisiana	2014	D-UD-13-01	9.95%
Entergy Mississippi Inc.	ETR	Electric	Mississippi	2014	D-2014-UN-0132	10.07%
Connecticut Light & Power Co.	ES	Electric	Connecticut	2014	D-14-05-06	9.17%
NSTAR Gas Co.	ES	Natural Gas	Massachusetts	2015	DPU 14-150	9.80%
Public Service Co. of NH	ES	Electric	New Hampshire	2010	D-DE-09-035	9.67%
Western Massachusetts Electric	ES	Electric	Massachusetts	2011	DPU 10-70	9.60%
Yankee Gas Services Co.	ES	Natural Gas	Connecticut	2011	D-10-12-02	8.83%
Jersey Cntrl Power & Light Co.	FE	Electric	New Jersey	2015	D-ER-12111052	9.75%
Kansas City Power & Light	GXP	Electric	Kansas	2015	D-15-KCPE-116-RTS	9.30%
Kansas City Power & Light	GXP	Electric	Missouri	2015	C-ER-2014-0370	9.50%
KCP&L Greater Missouri Op Co	GXP	Electric	Missouri	2013	C-ER-2012-0175 (MPS)	9.70%
Idaho Power Co.	IDA	Electric	Oregon	2012	D-UE-233	9.90%
Madison Gas and Electric Co.	MGEE	Electric	Wisconsin	2014	D-3270-UR-120 (Elec)	10.20%
Madison Gas and Electric Co.	MGEE	Natural Gas	Wisconsin	2014	D-3270-UR-120 (Gas)	10.20%
NorthWestern Corp.	NWE	Electric	Montana	2010	D-D2009.9.129 (elec)	10.25%
NorthWestern Corp.	NWE	Natural Gas	Montana	2013	D-D2012.9.94	9.80%
Oklahoma Gas and Electric Co.	OGE	Electric	Arkansas	2011	D-10-067-U	9.95%
Oklahoma Gas and Electric Co.	OGE	Electric	Oklahoma	2012	Ca-PUD201100087	10.20%
Otter Tail Power Co.	OTTR	Electric	Minnesota	2011	D-E-017/GR-10-239	10.74%
Pacific Gas and Electric Co.	PCG	Electric	California	2012	Ap-12-04-018 (Elec)	10.40%
Pacific Gas and Electric Co.	PCG	Natural Gas	California	2012	Ap-12-04-018 (Gas)	10.40%
Arizona Public Service Co.	PNW	Electric	Arizona	2012	D-E-01345A-11-0224	10.00%
Public Service Co. of NM	PNM	Electric	New Mexico	2011	C-10-00086-UT	10.00%
Texas-New Mexico Power Co.	PNM	Electric	Texas	2011	D-38480	10.13%
Portland General Electric Co.	POR	Electric	Oregon	2015	D-UE-294	9.60%
South Carolina Electric & Gas	SCG	Electric	South Carolina	2012	D-2012-218-E	10.25%
South Carolina Electric & Gas	SCG	Natural Gas	South Carolina	2014	D-2014-6-G	10.25%
Northern States Power Co. - MN	XEL	Electric	Minnesota	2015	D-E-002/GR-13-868	9.72%
Northern States Power Co. - MN	XEL	Natural Gas	Minnesota	2010	D-G-002/GR-09-1153	10.09%
Northern States Power Co. - MN	XEL	Electric	North Dakota	2014	C-PU-12-813	9.75%
Northern States Power Co - WI	XEL	Electric	Wisconsin	2015	D-4220-UR-121 (Elec)	10.00%
Northern States Power Co - WI	XEL	Natural Gas	Wisconsin	2015	D-4220-UR-121 (Gas)	10.00%
Public Service Co. of CO	XEL	Electric	Colorado	2015	D-14AL-0660E	9.83%
Public Service Co. of CO	XEL	Natural Gas	Colorado	2013	D-12AL-1268G	9.72%
Southwestern Public Service Co	XEL	Electric	New Mexico	2014	C-12-00350-UT	9.96%
Southwestern Public Service Co	XEL	Electric	Texas	2015	D-43695	9.70%

Notes:
[1] Operating Subsidiaries with rate cases not covered by SNL Financial were excluded from the analysis.
[2] Operating Subsidiaries with rate cases that were silent with respect to traditional rate case parameters were excluded from the analysis.
[3] Excludes Operating Subsidiaries with most recent rate case prior to 2010.
[4] Kansas Gas and Electric Co. was labeled as Westar Energy Inc. since the two companies file rate cases jointly.

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

Carmine Tilghman

on Behalf of

UNS Electric, Inc.

May 5, 2015

EXHIBIT
UNSE 25
admitted

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.

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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

Rebuttal Testimony of

Carmine A. Tilghman

on Behalf of

UNS Electric, Inc.

EXHIBIT
UNSE 26
admitted

January 19, 2016

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Carmine Tilghman and my business address is 88 East Broadway, Tucson, Arizona, 85702.

Q. Did you file Direct Testimony in this proceeding?

A. Yes.

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

A. My Rebuttal Testimony is filed on behalf of UNS Electric, Inc.

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

A. I will primarily be addressing comments from the testimony of ACC Staff witnessness Howard Solganick and Eric Van Epps, the Residential Utility Consumer Office ("RUCO") witness Lon Huber, Vote Solar ("VS") witness Briana Kobor, Arizona Utility Ratepayer Alliance ("AURA") and TASC witness, Mark Fulmer.

Q. Will you be addressing all of the issues included in testimonies relative to the Company's proposed net metering changes?

A. No, I will be limiting my rebuttal testimony to the following issues:

1. Requests to delay addressing the Company's proposal to modify the Commission's Net Energy Metering policy ("NEM") due to the Commission's pending Docket No. E-0000J-14-0023 (Value and Cost of Distributed Generation).

2. Clarification of the Company's proposal to utilize utility scale pricing as a Renewable Credit Rate, including clarification of Renewable Energy Credit ("REC") ownership and other factors affecting the use of a facility connected to the distribution system of UNSE's affiliate company, TEP.

3. The supposed benefits of distributed generation over centralized PV.

My lack of rebuttal testimony addressing other positions regarding UNSE's NEM proposal taken by Intervenors in their testimonies should not be taken as agreeing with or supporting these positions, and I reserve the right to discuss those issues as they arise during the hearing.

Q. Was there a common theme among the Intervenors' positions regarding the Company's net metering proposal?

A. No. Of the 15 parties in this proceeding that provided written testimony, only six addressed UNSE's proposed changes to the NEM policy in their direct testimonies. TASC, AURA, and Vote Solar oppose any changes to the current subsidies received from retail net metering; and in general, they oppose making any changes to the NEM policy until the Value and Cost of Distributed Generation docket has been completed. Moreover, they opposed demand charges and raising the monthly customer charge and any other proposal designed to mitigate the cost shift caused by current NEM policies and current rate design.

In contrast, RUCO's testimony addressed the need to ensure fairness for all ratepayers and offered several alternatives to the Company's NEM proposal, while the Arizona Investment Council ("AIC") supports UNSE's proposed modifications. ACC Staff testimony states that, for the time being, it does not endorse the Company's NEM proposal, but may update its position during the course of this rate case proceeding.

II. TIMING OF NET METERING MODIFICATIONS.

Q. Does the Company believe it is appropriate to wait until the Value and Cost of Solar docket is completed before considering proposed changes to NEM as part of UNS Electric's rate case?

A. No. Ironically, when the Company proposed addressing NEM as a stand-alone issue in March 2015, many of these same entities strongly argued that this issue must be addressed in a rate case. Their argument was that the Commission should be afforded the opportunity to address all rate design options at once, and that the Company's next general rate case was the appropriate place to do so. Attempting to remove the Company's proposal from consideration in this rate case until the Value of Solar docket is completed is a direct contradiction of their previously stated position.

Q. Have any of the Intervenors proposed rate design structures that either complement or mitigate the need to address modifications to the current NEM policy?

A. Yes, Staff has proposed a three-part rate structure that, if properly designed and implemented in a timely manner, would eliminate the need to specifically address the current NEM policy. However, not all parties support the implementation of a three part rate design that includes a demand component. Given the divergence of positions, the Company believes it is critical to evaluate all potential rate design proposals, including modifications to NEM, in this rate case.

Q. Do you agree with Ms. Kobor's argument that the problem is not large enough to warrant any changes to address the cost-shift due to DG systems?

A. No. Ms. Kobor simply points to a snapshot in time to justify her position. But the fact is that the cost-shift due to DG is a growing problem. Assuming that her conclusion is true (and we are not conceding that at this time) she ignores the increasing amount of DG

installations that is and will augment the decline in retail sales beyond 6%. Put simply, the Commission has found that a cost shift exists with non-DG customers subsidizing DG customers. Vote Solar and other parties stated that the rate case is the appropriate forum to address this problem; so now is the time to address this problem while it is at a manageable level.

Moreover, I do not believe it is appropriate to wait until there is a certain level of DG penetration in the market before the Commission addresses an acknowledged problem.

Q. Has the Commission made a specific finding that net metering is causing a cost shift to non-DG customers from DG customers?

A. Yes. Decision No. 74202 (December 3, 2013) recognized that a cost-shift due to net metering exists. Further, while it may have been justified in the past to have in place current net-metering policies to boost the proliferation of DG systems, this is no longer the situation we have. We have reached the point where subsidizing DG customers by crediting excess energy from DG systems at the full retail rate (by the banking of excess generation and rolling over kWh unused to subsequent billing periods) is not necessary, and is not (and never has been) supported by cost-of-service.

Q. Has TASC continued its opposition to any changes to net metering even when there has been substantial increased penetration of DG?

A. Yes. The Hawaii Public Utilities Commission recognized that penetration had reached a level to warrant changes including with its net metering policy - noting that total net metering program capacity had reached between 30% and 53% of each of the HECO Companies system peak load.[1] Keep in mind that UNS Electric is not proposing the changes the Hawaii PUC ultimately adopted, which was to end the current program in

[1] See Decision and Order No. 33258 in Docket No. 2014-0192 (October 12, 2015), pages 160-161(link : http://puc.hawaii.gov/wp-content/uploads/2015/10/2014-0192-Order-Resolving-Phase-1-Issues-final.pdf).

favor of new options for new DG customers. Still, even with that level of penetration, TASC filed suit in Hawaii challenging that Commission's decision that TASC alleges "the state's successful net energy metering program."[2] So even at the level of penetration TASC still opposes changes even when the Hawaii PUC clearly states that the intent of the NEM program was to merely provide "a simple and effective tool to jumpstart the adoption of distributed renewable energy" (as stated on page 162 of the Hawaii PUC's order).

Q. Are there other benefits or reasons to address current NEM policies now?

A. Yes. There is an inherent flaw in the current NEM policy that utilizes retail rates as a "rough justice" for compensation. By failing to send accurate price signals to the customer and the industry, there is little incentive for the industry to evolve its business model and promote new technologies. Rate design structures, including NEM policies, which reflect a more accurate cost of service promote the development of new technologies such as small scale storage and fuel cell technologies. Additionally, flawed and inaccurate price signals such as retail net metering do not promote customer education and do little to promote energy efficiency or demand side management.

Ultimately, most industry experts understand and believe that advanced technologies must be developed and deployed in order to achieve a more interactive grid, also referred to as the "grid of the future" or "grid 2.0". In order to promote the development of the appropriate new technologies, the correct price signals must be sent to the industry. This includes updating antiquated NEM policies that utilize retail rates at the compensation value.

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[2] See Press Release, "TASC Seeks an Injunction on the Decision to Eliminate Solar Net Metering in Hawaii" located at http://allianceforsolarchoice.com/tasc-seeks-an-injunction-on-the-decision-to-eliminate-solar-net-metering-in-hawaii/ (last checked January 13, 2016).

III. RESPONSE TO CONCERNS ABOUT UNS ELECTRIC'S NET METERING PROPOSAL.

Q. Is UNS Electric proposing to eliminate net-metering?

A. No.

Q. Is UNS Electric's proposal consistent with the definition of net metering in the ACC rules?

A. Yes. Amending the excess energy credit does not eliminate the "net" in net metering. Customers still have opportunity to receive a credit for excess energy that offsets energy provided by UNS Electric at the RCR level - in addition to offsetting energy the customer uses from the customer's DG system.

Q. In fact, is UNS Electric proposing to maintain the full retail rate offset for energy that the DG customer consumes from the customer's DG system?

A. Yes. The Company will credit every kWh of energy produced from the DG system that the customer uses at the full retail rate. The only change is with regards to excess energy that flows back onto the grid from the DG customer's system.

Q. Does UNS Electric's proposal eliminate net metering in favor of a "buy all sell all arrangement"?

A. No, because UNS Electric would not be acquiring energy from the DG customer at a specific rate for the energy that DG customer uses in addition to excess energy. And UNS Electric is not selling the excess energy back to the DG customer at the full retail rate. UNS Electric is acquiring the excess energy at a set rate that, while different than the full retail rate, is still offsetting energy provided to the DG customer from UNS Electric.

Q. Can you summarize why UNS Electric believes the Renewable Credit Rate ("RCR") it proposes is in the public interest to adopt for the excess energy credit?

A. Yes. While other UNS Electric witnesses detail the intricacies of cost of service, cost causation and the like, the RCR is a far better reflection of the cost of energy produced by DG than the retail rate. A DG customer does not incur the fixed costs associate with the distribution grid to ensure the deliverability of any energy from the DG system, for example. But those costs are embedded in the volumetric per-kWh retail rate charged to the customer. While UNS Electric's proxy as to the RCR is not perfectly precise, it much better reflects the actual cost to produce the energy.

Q. What issues were raised by Intervenors regarding the use of a utility scale solar price as the proxy for the Company's proposed Renewable Credit Rate?

A. Several Intervenors raised concerns regarding the use of a utility scale PPA price as the proxy for the proposed RCR, including:

1. The use of a Power Purchase Agreement ("PPA") associated with UNSE's sister company, TEP, which has the ability to deliver both energy and REC's to UNSE.
2. PPA price not accounting for transmission or distribution losses.
3. Accounting for potential deferred savings at the distribution level.
4. That a utility scale solar facility is not a fair proxy for Distributed Generation ("DG").
5. Changing or resetting the Renewable Credit Rate.

I will address each of these issues individually. Although there were other issues raised by Intervenors (primarily TASC), they are not significant enough to include in my rebuttal testimony and can be more easily addressed and discussed during the hearing process.

Q. Please discuss the specific issue regarding the use of a PPA price associated with UNSE's sister company TEP, and why the Company still believes it is appropriate to consider.

A. Several Intervenors believe it is inappropriate to establish the Renewable Credit Rate based on a facility that is tied to an expansion of an existing facility, or one that is not directly tied to the UNS Electric system.

For example, Staff argued that it would not be representative of the facilities' actual costs to UNS Electric if the Company were to utilize an existing facility's interconnection and procure solar energy for a lower price (thereby "artificially" lowering the Renewable Credit Rate). It should be noted that, as stated in the Company's response to Staff's data request, the second phase of the TEP facility used in setting the Renewable Credit Rate had its own interconnection costs totaling more than $1.7 million that were included in the contract price.

It should be noted that the Company does, in fact, have the opportunity to take advantage of existing facilities to procure lower priced energy – a benefit which is passed on to the customer. This is the very basis of argument that the Company possesses the ability to procure renewable energy – with arguably equal or superior benefits to customer-sited DG – at a lower cost.

If, in fact, future utility scale projects had a higher price due to interconnection costs, transmission costs, or other variable costs, they would be reflected in a higher PPA price and subsequently in a higher Renewable Credit Rate.

However, at this time, the Company believes that it's inherently unfair that customers should have to pay more than the price at which the Company is currently able to procure solar energy, and the Company fully intends to continue procuring renewable energy at the most cost competitive prices. Moreover, no Intervenor has provided any compelling reason or argument as to why customers should pay more for solar energy.

Several Intervenors question why the Company should be allowed to utilize solar energy from a facility not connected to UNSE's system. The question, however, should be *why wouldn't the Company take advantage of its ability to procure lower cost renewable energy?* The Company's proposal was designed to allow the Company to meet the state's Renewable Portfolio Standard ("RPS") in *the most cost effective manner possible.* Arizona's RPS does not require the renewable energy that serves an affected utility's customers be produced within the company's service territory. The requirement is that the energy be from eligible renewable energy resources (as defined in A.A.C. R14-2-1802) and that these resources *"displace conventional energy resources that would otherwise be used to provide electricity to an affected utility's Arizona customers."* Additionally, the RECs from these resources (except distributed resources) must only demonstrate the delivery of the renewable energy to the affected utility's retail customers (such as through the procurement of transmission rights for the delivery of the energy).

TASC witness Fulmer's testimony states that *"while TEP is an affiliate of UNS, it is not UNS. This begs the question, 'why not Arizona Public Service (APS) or Salt River Project (SRP) or even Nevada Power, whose load center (Las Vegas) is closer to the bulk of UNS's load than Tucson is?'"* UNSE agrees – why not one of those other companies? Any of those companies may very well afford UNSE the opportunity to procure renewable energy for its customers at a *significantly lower cost* than continuing to pay a

retail customer approximately double the current rate, all while being able to deliver the energy to the Company's retail customers and satisfying the requirements of the RPS.

While the Company would entertain a much broader discussion in a future rulemaking proceeding regarding the most cost-effective use of regional facilities, the Company's proposal is that avoided cost would be based on a system attached to a "distribution system," which ensures that the facility must be in the State of Arizona and tied to either UNSE's or TEP's distribution system.

Q. Please discuss who owns the RECs associated with the Company's proposal, versus the proposals of the Intervenors.

A. As with all utility scale renewable PPA's – including the proposed project used to establish UNSE's proposed Renewable Credit Rate – the Company's retains all of the RECs. In fact, while Staff witness Solganick expressed concern regarding REC ownership, he also stated that "this is important as REC's have value".

If this concept is to hold true, then it is important to note that the Company retains the right to all RECs associated with the utility scale PPAs. Conversely, and conspicuously missing from all of the Intervenors testimony, is the fact that the Company does not obtain title to the RECs associated with customer-owned renewable DG systems. This further diminishes the value of a customer-owned DG system relative to a utility-scale renewable facility where the utility is able to obtain REC ownership for compliance with the RPS.

Q. Please discuss Intervenors' concerns regarding avoided losses.

A. Several Intervenors expressed concern over not providing the DG customer compensation for avoided losses. This is one area where the Company would concede, with certain

caveats, that loss compensation could be considered in the Renewable Credit Rate. Overall, total losses on an electrical grid (transmission, distribution, and conversion) represent approximately 10% of the system cost. As such, even if the entire system losses were deemed to be saved it would only translate into an increased Renewable Credit Rate of about 6.5 cents per kWh, which is still only slightly more than half the current retail rate. However, the Company does not agree that the entire system loss value should be included in the compensation value, and would include the caveats below:

1. Only real losses should be included, and only those losses associated with the distribution system should be included, as the Company's proposal stipulated that the renewable credit rate would be based on a corresponding facility attached to a distribution system. RECs can easily be transferred between companies, and the ability to utilize either company's distribution system benefits UNSE and TEP customers alike. Any concern regarding "significant losses" associated with a third party's transmission system highlights a lack of understanding of the Company's proposal.
2. A reasonable estimate of losses associated with energy pushed back onto the grid should be deducted from any loss compensation adder. While the parties may argue about precise values, it is not uncommon to see approximately 50% of a customer's energy pushed back onto the grid. Many solar proponents argue that energy only "goes to the house next door". However, there are several factors that should be considered when making that as-yet-to-be-proved claim: increasing penetration of DG results in multiple solar customers on each circuit, all pushing energy back into the distribution circuit level; when the solar customer isn't using the energy due to low load, the neighbor often has low load, as well; energy pushed back through the lowest voltage portion of the system has the highest loss percentage (due to the higher current flows at low voltages resulting in higher

eddy current losses). While all of this information is extremely difficult to measure and quantify, it is at the very least necessary to acknowledge the existence of these losses and provide some reduction.

Q. Please address the Intervenors' comments that a utility scale facility is not a fair proxy for distributed generation.

A. Several Intervenors questioned the basis for using a utility scale facility as an equitable proxy for distributed generation. TASC witness Fulmer even went so far as to claim that "the fact that DG is distributed makes it a more reliable and steady source of power than even smaller utility scale projects." In a theoretical world where customer sited DG was evenly distributed throughout the utility's system, it would provide a smoother – yet equally unreliable – power source.

However, we do not live in a theoretical world. The "competitive" solar industry does not install solar in a well-planned, thoughtful manner with an emphasis on improving grid reliability, but rather wherever they find a willing and financially capable customer. As a result of such a random disbursement of DG, which lacks even a hint of thoughtful distribution planning, Mr. Fulmer's and Ms. Kobor's claims that there is a benefit of intermittency smoothing that lacks any credible, real-world evidence. At best, in my experience and observation of the roughly 13,000 DG systems between UNS Electric and TEP, there is no material benefit of randomly sited DG over well-planned, smaller scale centralized PV facilities. In my opinion, Mr. Fulmer's and Ms. Kobor's assertions that the effect of randomly located solar DG is of tremendous value to the utility, simply highlights the witnesses' lack of actual grid management and operational expertise. Mr. Fulmer's additional reliance on the DOE's Solar PEIS study and the assertion that land use impacts such as soil disturbance, habitat fragmentation, noise, and surface water quality prove that DG is more valuable than utility scale PV shows a lack of

understanding and ignorance of the Company's long established procedures for siting facilities on previously disturbed or limited use properties. The Company's site selection process either minimizes or eliminates these impacts. Even without the Company's site selection criteria to minimize these impacts, it is irrational to argue that any minimal environmental impact associated with utility scale facilities justifies a solar DG credit equal to twice the cost of energy from utility scale facilities.

TASC witness Fulmer further goes on to claim that the Company's proposal is unfair as the value of renewable power is not the same across technologies, and then proceeds to use the example of the utility procuring a geothermal project with a lower price than solar, or the possibility of a wind facility whose generation profile would be different but again, whose price would be lower. Mr. Fulmer then proceeds to erroneously state that "solar provides power during times of high system load when power is more valuable", once again highlighting his lack of actual operational experience in grid management and relying on an often repeated, yet incorrect, statement that applies to only a few months during the year. The Company has previously shown that at no time during the year does the system peak when solar peaks. In fact, during the winter months when the system peaks before the sun rises and after the sun sets, solar has absolutely zero value during the times of greatest need and when prices are the highest.

The Company questions why Mr. Fulmer would be *concerned* that the Company could procure renewable resources at a lower cost. If, in fact, we could provide our customers with renewable energy from a resource that is a lower cost to the customer, exactly what is the concern? The Company fails to see the logic in TASC's argument that UNSE should be precluded in the future from procuring lower cost resources simply because it makes TASC's member companies' product less economical. Perhaps Mr. Fulmer unintentionally highlights the flaw in TASC's continued fight to preserve the NEM

subsidies as they exist today – an acknowledgment that there are cheaper renewable resources available to the utility than customer sited DG.

Q. What is your response to Ms. Kobor's apparent dismissal of DG adversely impacting UNS Electric's grid?

A. As I have stated and based on my experience observing how the growth of DG impacts UNS Electric's grid, the random way by which DG systems are added onto UNS Electric's system will necessitate measures and improvements to address some of the stability issues caused by DG proliferation. If this were a situation that renewable energy systems were placed strategically throughout UNS Electric's service territory, the need for additional improvements of this type could perhaps be minimized. But that is not the case with DG. Like with the intermittency issue (DG systems are not well-planned to cost-effectively reduce intermittency) the need for ancillary services (such as voltage or frequency control) will increase with increased DG proliferation. So, just as widespread proliferation of DG systems is not the sole panacea for intermittency of renewable energy such as solar, the random proliferation of DG results in side effects that adversely impact the grid, where alternative renewable resources strategically placed would lessen such adverse impacts.

Q. What can you tell us about the reverse power flows UNS Electric has experienced with increased DG?

A. Our actual experience operating UNS Electric's distribution grid has shown such reverse power flows during routine or specific testing. The fact is that to put specific monitoring equipment for every one of the hundreds of circuits would be extremely costly if not impossible. But we do know for sure this phenomenon has occurred and exists. As the entity charged with ensuring safe and reliable service, we have to address it.

Q. Mr. Fulmer, at page 9 of his November 6, 2015 Direct Testimony indicates his belief that UNS Electric has not provided sufficient information to demonstrate any integration issues with increased DG. What is your response?

A. Mr. Fulmer ignores the continuing flow of applications that UNS Electric is receiving from customers seeking to install DG. In other words, the number of DG systems interconnected onto UNS Electric's system keeps increasing in response to market opportunities instead of distribution planning. As a result, integration issues arise that require additional equipment that may include smart inverters and other facilities to manage the load and provide stability. I note that UNS Electric continues to receive applications to interconnect DG systems even with notification of the potential changes to rates and the net metering tariff.

Q. Is the Company insistent that the Renewable Credit Rate be reset each year based on the most recent utility scale PV price, or could the Company support a compromise in order to provide some price stability?

A. The Company's proposal is to reset the rate each year. However, the Company would be willing to discuss alternatives in order to provide some price stability, thereby eliminating the concern over changing pricing. These alternatives could include fixing the NEM credit until the Company's next general rate case, or possibly for a longer period of time, when the credit would be recalculated based on more current price information.

IV. RECENT NET METERING POLICY DEVELOPMENTS.

Q. Have there been any regulatory developments or utility commission decisions regarding NEM changes that support the Company's position that the current NEM policy should be changed?

A. Yes, several Public Utility Commissions ("PUCs") have recently made significant policy changes to their states' NEM policies, or have made significant findings in orders regarding net metering. Each of these states have (or had) full retail net metering policies similar to the current Arizona policy. I believe that the PUCs have, in general, correctly identified concerns and problems with NEM policies that are generally applicable in Arizona and that those PUCs have begun the process of making necessary changes in NEM policies to reflect the current - and evolving - circumstances.

In October of 2015, the Hawaii Public Utilities Commission voted to eliminate their retail net metering program in favor of a payment for excess energy pushed back onto the grid that is *less than half of the retail rate* and is based on the avoided cost of fossil fuel during peak generation hours.[3] If UNSE employed this type of payment mechanism, the proposed Renewable Credit Rate would be approximately $0.035-$0.040/kWh rather than the equivalent utility scale price of $0.0584/kWh that the Company proposed. In their decision the Hawaii PUC stated, *"It is abundantly clear that distributed energy resources can provide benefits to Hawaii. It is also clear, for both technical and economic reasons, that the policies established more than a decade ago must be adapted to address the reality of distributed energy resources as they exist today – and as they are likely to develop in the near future."* The Company agrees that, even though there may be different challenges between UNSE and HECO, the idea that policies established a decade ago must be adapted to reflect the current situation and reality of distributed generation resources, particularly in light of the Company's ability to procure lower cost renewable resources in other forms.

[3] Decision and Order No. 33258 in Docket No. 2014-0192 (October 12, 2015) (link : http://puc.hawaii.gov/wp-content/uploads/2015/10/2014-0192-Order-Resolving-Phase-1-Issues-final.pdf).

In November 2015, the Utah Public Service Commission issued an order in the matter of the investigation of the costs and benefits of PacifiCorp's net metering program.[4] The order is considered the first step in fulfilling a legislative statute and is designed to provide the framework of how to calculate benefits and costs of net metering. The second step, which has not been completed, will address the actual value at which excess energy from NEM customers should be set. What is important in this order is the Utah Commission's rejection of claims made by the Joint Parties (representing several solar entities, including TASC) that a customers' DG equipment is a "free resource to the utility system" and the costs and benefits of net metering are analogous to the analysis used by the utility in its Integrated Resource Planning ("IRP"). In the current UNSE rate case, Intervenors have claimed that energy received by the utility from net metering customers has significant value over well-planned utility-scale PV systems and should be therefore be valued higher. However, the Utah Commission correctly determined a number of fallacies related to this argument, such as:

1. NEM generation results from a voluntary customer decision, and the utility has little, if any, control over the design of systems on the customer side of the meter.
2. Customers own and control their equipment, and customers make decisions about whether to install that equipment and how much capacity to install.
3. The customer is under no obligation to maintain the system.
4. The customer is under no obligation to supply the utility with electricity.
5. If a problem develops that prevents the customer from generating energy, the customer is under no obligation to cure it.
6. A customer is under no contractual obligation to provide any of the power it generates to the utility.

[4] Order in Docket No. 14-035-114 (November 10, 2015)
(link: http://www.psc.state.ut.us/utilities/electric/ordersindx/documents/27044914035114o_000.pdf)

All of these observations regarding a customer sited DG system are applicable to every utility with a similar NEM program, including UNSE. However, as PacifiCorp noted and the Utah Commission agreed, the utility's contractual agreements provide for robust credit terms, performance guarantees, step-in rights, and other provisions that ensure the facilities will produce energy for the benefit of all customers. All of UNSE's contracts contain these provisions, along with other valuable attributes such as communications networks for system monitoring, ability to control or shutdown the systems, protection devices, and ownership of the RECs. TASC and other Intervenors' arguments that a customer sited DG system is more valuable ignores all of these circumstances.

Finally, on December 22, 2015 the Nevada Public Utilities Commission voted unanimously to lower the rate applied to net metered energy from distribution generation customers from approximately 11.5 cents per kWh to about 5.5 cents per kWh.[5] This value, calculated by NV Energy in their integrated resource plan, represents the forecasted average annual marginal energy cost (with an adder for avoided distribution line losses). This amount is representative of the value UNSE has proposed through the use of its avoided solar value (the wholesale price for the Renewable Energy Credit rate).

The Nevada PUC also made a number of determinations in support of, and consistent with the Utah PSC's findings, lowering the value associated with energy from NEM customers. Specifically, the Nevada PUC stated:

1. Current rates for NEM ratepayers are not properly aligned with the costs to serve NEM ratepayers. The misalignment can be attributed in part to the NEM policies.
2. Rates are based on marginal (internal utility) costs and do not reflect external benefits or costs for any ratepayer class. External societal costs and benefits are

[5] Order in Docket Nos. 15-07041 and 15-07042 (December 23, 2015) (link: http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2015-7/8412.pdf)

not included in the cost recovery that NV Energy's rates provide for any class. No exception should be made for NEM ratepayers.

3. NEM ratepayers have unique service and cost characteristics, and as such, NEM ratepayers should be placed in a separate rate class in order to allow for alternative rate structures.

4. Separate rate classes will address the inequity between NEM and non-NEM ratepayers that exists under their current NEM structure (which is nearly identical to Arizona's NEM structure).

5. It is in the public interest to take steps to transition to accurate, cost-based, non-discriminatory rates.

6. The value of NEM changes over time based on a variety of factors – relative location and concentration, natural gas prices, and the price of utility-scale renewable amongst other things. Consequently, setting a value for a long period of time is unwise.

7. Banking the net excess energy at the retail rate is not just and reasonable because the energy by the NEM ratepayers is not the same as the energy delivered by NV Energy.

8. NV Energy is required to provide reasonably reliable service at just and reasonable rates. NV Energy is required to provide this service at the times and place and in the volumes required by any ratepayer, including a NEM ratepayer.

9. This requires that the utility adhere to industry standards for the design and operation of its electric system including system reserves and redundancies. Failure to provide this service can result in fines and the revocation of NV Energy's operating certificate.

10. In contrast, NEM ratepayers have no legal requirement to provide any volumes to the grid at any time. NEM provide these volumes solely at the discretion of each

individual NEM ratepayer and are not scheduled in advance and can be withdrawn at any time by the NEM ratepayer.

11. Further, the volumes flow to the grid without consideration for overall grid demand or system reliability which remains the legal responsibility of NV Energy.

12. Ratepayers are smart, capable, and willing to participate in a market that is based on cost causation and fairness.

13. Acknowledges independent analysis conducted by E3, Lawrence Berkeley National Laboratory, and the Massachusetts Institute of Technology support the conclusion that NEM increases utility rates and shifts costs to non-participating ratepayers.

On January 13, 2016, the Nevada Public Utilities Commission unanimously reconfirmed their decision over the objections from several intervenors, including TASC.

While each of these examples are unique in their own right, they highlight the fact that continued use of existing NEM policies such as full retail net metering is unsustainable.

While the Company is open to further discussion regarding the credit rate used for net metered energy and length of time before such rate should be adjusted (annual, in each rate case, etc.), the Company still firmly believes that, in the absence of any significant rate design changes, now is the appropriate time – and this rate case is the appropriate venue – to implement changes to the current retail NEM policy.

V. RESPONSE TO REQUEST FOR REST PLAN OF ADMINISTRATION.

Q. Are there any other issues that you would like to address in this testimony?

A. Yes. The Direct Rate Design Testimony of Eric Van Epps recommends that the Company provide a draft Plan of Administration ("POA") for the REST in the Company's rebuttal testimony. Following discussions to clarify Staff's request for a POA and what additional data is to be included, the Company will draft a POA that is consistent with the requirements set forth in A.A.C. R14-02-1813 governing Affected Utility's renewable implementation plans. Due to the nature of the request and timing associated with the development of the POA, the Company will provide a draft POA prior to the hearing in this matter.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

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

Rejoinder Testimony of

Carmine A. Tilghman

on Behalf of

UNS Electric, Inc.

February 29, 2016

EXHIBIT
UNSE 27
admitted

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Carmine Tilghman and my business address is 88 East Broadway, Tucson, Arizona, 85701.

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

A. Yes, I filed both Direct and Rebuttal testimony in this proceeding.

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

A. I will be addressing portions of Staff Witness Broderick's testimony; Staff Witness Liu's testimony; TASC Witness Fulmer's testimony; and APS Witness Brown's testimony.

Q. Staff recommended that net metering be continued without changes, contingent upon the Commission accepting their recommendation to migrate from two-part to three-part rates, and requested a confirmation that UNSE would be willing to accept this recommendation until at least its next rate case. Does the Company accept these positions?

A. Not entirely. In my Rebuttal Testimony (page 3, lines 17-18), I stipulated Staff's proposed three-part rate structure would eliminate the need to specifically address the current NEM policy *if properly designed and implemented in a timely manner* (emphasis added.) As Mr. Broderick noted in his Surrebuttal Testimony, compensation to DG solar customers will be higher under the most recent rate design proposal due to the higher kWh rates being offered and the ability to over-generate energy during the winter months for use in the summer months. The current three-part design structure currently proposed is a transitional structure specifically designed to minimize the impacts to

customers transitioning to a new rate structure, and continues to send the incorrect price signal for the design and installation of DG solar. The Company still believes the elimination of monthly rollover (banked kWh for use in later months) and the application of a market-based proxy rate (renewable credit rate) is still the most appropriate method for excess energy delivered to the grid from a solar DG system. To be clear, the Company has only proposed this NEM policy change be effective for those customers who submitted an application after June 1, 2015, and that customers who submitted an application by June 1, 2015 remain on the current NEM rate structure.

The Company does, however, appreciate Staff's willingness to find common ground during this transitional period, and the Company would like to be supportive of this position. The Company does not, however, agree with the idea that NEM policy changes must wait until the Company's next general rate case. The Company disagreed with Staff and the intervening parties' position that NEM changes should be made through a general rate case, and continues to disagree with that position. If Staff is going to maintain its position that the results of the pending Value and Cost of Solar docket (No. E-00000J-14-0023) cannot be applied until the Company's next general rate case, then the Company strongly asserts that the issue be addressed in this rate case, as originally contemplated.

The Company has previously presented arguments in support of changing the current NEM policy, with additional supporting Surrebuttal Testimony by APS Witness Brown. At this time, the Company would like to reserve the right to continue the discussion of NEM changes during the hearing, while the idea of a properly designed and implemented three-part rate design structure is being contemplated.

Q. TASC Witness Fulmer again asserts that geographically dispersed DG provides a "smoother" more reliable solar power source than a central station. Do you agree with this statement?

A. No. Mr. Fulmer supports his diversity claim by relying on several studies that compare multiple DG sites to a single utility scale facility. If the Company were only discussing the proliferation of DG relative to a single utility scale facility, I would concur with the conclusion. However, what Mr. Fulmer fails to acknowledge is that the utility is developing multiple utility scale facilities, located in multiple regions, spread across the entire UNSE service territory.

As I previously noted in my Rebuttal Testimony, the dispersion of DG is predicated on the solar installer's ability find suitable customers to purchase or lease their systems without any regard to the system impact or reduction or overall variability. This process, which has historically been targeted to customers with either the financial means or necessary credit scores to procure a system, does not result in a well-planned, organized distribution of solar DG.

On the contrary, the Company's ability to procure and install multiple large scale solar facilities, consistent with integrated resource planning principles, provides similar geographic dispersion benefits without relying on the random nature of solar DG sales.

In addition, there are multiple forms of intermittency associated with solar DG. Mr. Fulmer only addresses solar "intermittency" as the overall impact to the grid, he fails to even acknowledge the intermittency impacts on the individual distribution transformer and feeder circuits, and the associated wear and tear, regardless of the supposed smoothing benefits of dispersed DG. Intermittency associated with utility scale solar does not impact these distribution components.

Finally, as previously noted, there are numerous benefits associated with utility scale solar not associated with DG, such as secure communications, downward ancillary services, and interoperability with the Company's system control and data acquisition system (SCADA).

Q. TASC Witness Mr. Fulmer provided a Value of Solar analysis in his Surrebuttal Testimony. Does the Company agree with Mr. Fulmer's assertions?

A. No, the Company does not agree with Mr. Fulmer's value of solar assertion. As the Commission currently has a Value and Cost of DG Solar docket in which TASC may attempt to validate their position, it is unnecessary to do so in this proceeding. However, the Company would like to note one very significant point regarding TASC's position: While Mr. Fulmer and TASC believe the benefits of DG solar to be on the order of $0.10-$0.14 per kWh, *at no time does Mr. Fulmer or TASC ever attempt to provide a justification why the ratepayers should pay twice the amount for solar than what the Company can procure for an equivalent amount of solar on its distribution system.*

Q. Both Staff Witness Liu and TASC Witness Fulmer provided calculations of the impacts of proposed rates on customers. Did you review the assumptions contained within their respective models?

A. Yes, but only as the assumptions related to the solar systems' production, installation costs, and other solar related data.

Q. Do you agree with the assumptions used by Staff and TASC? In not, please explain.

A. The data used by Staff witness Liu is reasonable; however, there were several discrepancies in the TASC model used by Mr. Fulmer. Several of these discrepancies were noted by Staff Witness Liu, particularly as it relates to the specified location, production, and installation costs. Specifically, the two major differences noted are:

1. Staff used Company provided data of 1,800 kWh/kw, while TASC provided Staff an annual production value of 1,698 kWh/kW (Liu Surrebuttal, page 5, line 4). While TASC Witness Fulmer did not provide a direct reference to the production value used in his calculation, footnote 57 contained in Mr. Fulmer's Surrebuttal Testimony (page 27) indicates the use of a customer whose average annual consumption of 18,000 kWh is 80% offset by an 8.5 kW solar system, implying an average annual production of 1,694 kWh/kw.
2. Staff selected a cost of installation of $2,750 per kW, which was the average of the $2,500 per kW provided by the Company and the $3,000 per kW provided by TASC (Liu Surrebuttal, page 7, line 9). Surprisingly, TASC Witness Fulmer did not use the same installed cost value that TASC provided to Staff, but rather used a much higher installed system cost of $3.60/watt, or $3,600 per kW (Fulmer surrebuttal, page 28, line 5).

Q. Have you reviewed the testimony provided by APS Witness Brown?

A. Yes, I have.

Q. Do you agree with Mr. Brown's conclusions regarding the use of large scale solar as a proxy for DG?

A. Yes. As the Company has previously stated, which is consistent with the conclusion by Mr. Brown, the use of large scale solar procured in a competitive market is the most appropriate method for pricing DG.

Q. A number of interveners have submitted Surrebuttal Testimony that is ideologically opposed to the positions you have previously stated in your testimony. Does your lack of acknowledgement of these statements in your rejoinder testimony mean your position, or the Company's position, has changed?

A. No. In the limited amounted of time available to provide Rejoinder Testimony, I have limited my testimony to addressing only a few of the Intervenors' comments. A lack of acknowledgement in my Rejoinder testimony regarding a specific interveners' Surrebuttal Testimony should not be construed as a change in the Company's previously stated position.

Q. Did Staff request the company to submit a draft Plan of Administration for its REST surcharge?

A. Yes. Attached as **Exhibit CAT-RJ-1** is an initial draft of the Plan of Administration that we will work with Staff to finalize. We would anticipate filing a final Plan of Administration for commission approval as part of our compliance filing following the issuance of a final commission decision in this case.

Q. Does this conclude your Testimony?

A. Yes, it does.

Exhibit CAT-RJ-1

UNS Electric, Inc.
Renewable Energy Standard and Tariff
Plan of Administration

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1. GENERAL DESCRIPTION

This document describes the plan for administering the Renewable Energy Standard and Tariff rules ("REST") and associated Implementation Plan ("IP" or "Plan"), as approved by the Arizona Corporation Commission ("Commission") in Decision No. 69127 (Nov 14, 2006), applicable to UNS Electric, Inc. ("UNS Electric"), and codified in the Arizona Administrative Code ("A.A.C.") R14-2-1801 through R14-2-1815. The REST provides the requirements and governance to affected utilities required to meet the Arizona Renewable Portfolio Standard ("RPS").

2. DEFINITIONS

Implementation Plan – The annual Company Plan that describes how it intends to comply with the Renewable Energy and Standard Tariff rules for the next calendar year.

REST Surcharge - An amount generally expressed as a rate per kWh, which reflects the per kWh charge applied to an individual customers billed usage, by customer class, designed to cover the cost of the Company's approved annual Implementation Plan budget.

REST Plan - The Company's Renewable Energy and Standard Tariff Implementation Plan approved by the Commission on an annual basis.

REST Year - A calendar year beginning January 1 and lasting through December 31.

REST Costs - The costs associated with the design, implementation, management, contracts, training, education, labor, and other services contained in the Company's Implementation Plan and incurred by the Company, which otherwise would not be incurred without the Commission's RPS mandate and which are not recovered through the Company's general retail rate structure.

All other terms and definitions associated with the REST are contained in the Arizona Administrative Code ("A.A.C.") Section R14-2-1801.

3. REST PLAN COMPONENTS

The REST Plan will consist of, at a minimum, the following components designed to meet the Company's annual requirements of the Arizona Renewable Portfolio Standard. Those components are:

1. Executive Summary: Designed to provide an overview of the Company's annual Implementation Plan.

2. Utility Scale Renewable Generation: A description of the Company's existing and proposed utility scale (grid tied) renewable generation; including but not limited to: facility location, size, expected production, and operational dates.

3. Distributed Renewable Generation: A description of the Company's existing and expected distributed renewable generation; including but not limited to: total residential and non-residential capacity, and expected annual production for both residential and non-residential. These values shall be reported regardless of system ownership or Renewable Energy Credit ("REC") ownership.

4. Market Cost of Comparable Conventional Generation ("MCCCG"): The equivalent market cost of energy and capacity associated with a particular renewable technology, typically shown as a weighted average annual value. The Plan shall include a description and associated exhibit showing the annual MCCCG rates stated as a single dollar per MWh value by technology type. At a minimum, the MCCCG will be calculated for the following technology types: wind, photovoltaic ("PV"), concentrated solar thermal, and biomass. The MCCCG for multiple regions may be included, as appropriate (i.e. – Arizona wind versus New Mexico wind).

5. Above Market Cost of Comparable Conventional Generation ("AMCCCG"): The difference between the Company's contractual obligation under a Power Purchase Agreement ("PPA") and the associated technology's MCCCG. The Plan shall contain an exhibit showing the annual AMCCCG values by contract and total required annual revenue based on expected production.

6. Line Item Budget: The line item budget shall contain, at a minimum, specific estimated budgeted amounts for the following categories. At a minimum, the budget shall contain the following:

   a. Utility Scale Energy Costs - AMCCCG costs associated with current or expected Power Purchase Agreements (PPA) for the associated implementation year. Additionally, any Commission authorized recovery of estimated carrying costs associated with Company owned investments shall be listed.

   b. Customer Sited DG Energy Costs – All costs associated with customer up front, performance based, or other Commission approved incentives shall be listed. Additional costs associated with customer based programs may be included, such as meter reading costs, consumer education and outreach programs, and other customer based program costs.

   c. Program Labor and Administration Costs –Internal labor costs that are not currently collected through the Company's base rates, as identified in the Company's previous general rate case, shall be listed. External labor costs, including temporary administrative support, student interns, and legal costs associated with the administration, preparation, and representation of the Company with regards to renewable energy shall be included. Administrative costs associated with materials, fees, supplies and other costs shall be listed.

d. Research and Development (R&D) Costs – All costs associated with Commission approved R&D programs shall be listed separately.

e. Carryover Funds – Carryover funds is the imbalance amount on the Company's annual compliance report that shows the difference between the amount collected by the Company for a specific year through its renewable energy surcharge and the actual amount spent on implementing the Commission approved implementation plan. This value will represent either an over-collection or under-collection funds by the Company relative to the actual cost of the previous year's implementation plan. This value shall be applied to the subsequent annual implementation plan budget (i.e. – an over-collected amount for the year 2015, as shown in Company's annual report filing on April 1, 2016, shall be applied to the budget for the 2017 implementation plan).

7. REST Tariff: The Company shall provide a proposed REST tariff and Statement of Charges, which shall include proposed per kWh charge and customer surcharge caps.

8. Associated Exhibits: The Company shall provide associated exhibits as required for the following:

   a. Budget
   b. MCCCG
   c. AMCCCG
   d. New resources plan and costs
   e. REST Tariff and Statement of Charges
   f. Renewable Energy Credit Purchase Program (as applicable)

4. CALCULATION OF THE REST RATE

The REST Tariff rate and associated customer caps shall be calculated annually, and while subject to variation, with the following principles in mind:

a. The annual per kWh rate and customer caps shall be designed to generate revenues to be approximately equal to the requested budget.
b. The percentage of revenues associated with each customer class should, within reason, attempt to approximate the percentage of sales from each class. Exceptions may be made for disproportionate economic impacts to a specific customer class if the Commission believes it is in the public interest.

Subject to Commission approval, the REST tariff rate shall be reset on January 1 of each year, and shall be effective with the first January billing cycle unless otherwise ordered by the

Commission. A REST tariff approved after January shall not be retroactive, and the any imbalance shall be collected subject to the provision of Carryover Funds described herein.

5. FILING AND PROCEDURAL DEADLINES

A. July 1Filing

UNS Electric shall file their proposed implementation plan no later than July 1 each year.

B. April 1 Filing

UNS Electric shall file their annual report no later than April 1 each year.

C. Additional Filings

UNS Electric will also file with the Commission any additional information that the Commission Staff determines pertinent to the Company's implementation or annual report filings.

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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

EXHIBIT
UNSE 28
admitted

Direct Testimony of

Dallas J. Dukes

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 Dallas J. Dukes and my business address is 88 East Broadway Blvd., Tucson, Arizona 85701.

Q. By whom are you employed and what are your duties and responsibilities?

A. I am the Senior Director of Pricing and Economic Forecasting for Tucson Electric Power Company ("TEP"). I am responsible for monitoring and determining revenue requirements, customer pricing and rates structures for all the regulated subsidiaries of UNS Energy Corporation ("UNS Energy"), including UNS Electric, Inc. ("UNS Electric" or the "Company").

Q. Please describe your background and work experience.

A. I hold a Bachelors of Science degree with a concentration in Accounting from Indiana University and a Masters in Business Administration from Anderson University. I am also a Certified Public Accountant. I have 25 years of experience within the utility industry. Before assuming my current position, I was employed as the Director of Accounting for TEP.

Prior to working for TEP, I was employed by Citizens Gas & Coke Utility ("Citizens Gas"), for approximately five years. Citizens Gas serves approximately 265,000 customers in the Indianapolis, Indiana area. The majority of my time at Citizens Gas was spent as the Controller.

Before then, I was the Controller and Director of Regulatory Affairs for Fountaintown Natural Gas Company, and Southeastern Indiana Natural Gas Company. Prior to that, I

was employed by the Indiana Office of Utility Consumer Counselor ("OUCC") for approximately seven years. The majority of my time at the OUCC was spent as a Principal Accountant. My primary duties at the OUCC were to perform professional investigative audits and to represent the public's interest as an expert witness in proceedings before the Indiana Utility Regulatory Commission.

Q. Could you please summarize your Direct Testimony?

A. I discuss the more significant Company proposals to change both residential and small commercial customer classes' rate structures. These changes include: (1) raising the basic service charges for residential and small general service customers; (2) eliminating one of the volumetric rate tiers from standard residential customer rate; (3) creating a new net-metering rider that allows the customer with distributed generation ("DG customer") to offset energy consumption with energy production at the retail rate and to sell excess energy production to UNS Electric at the Renewable Credit Rate; (4) requiring partial requirements customers (including new net-metering DG customers) to choose from one of the two proposed three-part rate tariffs applicable for their service requirement. UNS Electric is making these proposals to better align rate design with cost-causation and to reduce inter-class inequities. While the Company understands that there are several foundational rate-design principles, the primary principle remains that rates should reflect cost-based recovery. With that in mind, the Company's proposals address the many changes to the utility industry in recent years – including energy efficiency, distributed generation and demand response – that have contributed to flat or declining energy sales.

Right now, UNS Electric's current rate design for residential and small commercial customers does not reflect the way costs are incurred to serve the customers within these classes. The two-part rate structure of a basic service charge and energy charges is antiquated and does not reflect the modern and burgeoning market for new distributed

energy and demand-management options. The energy (kWh) consumption from seasonal customers and distributed generation customers (for example) is not reflective of the fixed costs imposed on the utility. Put simply, UNS Electric's ability to recover these fixed costs is limited.

Consequently, these unrecovered fixed costs are shifted to other customers under the present rate design. In particular, higher-use customers pay a higher percentage share of fixed costs despite the fact that the fixed costs to serve similar lower-use customers is the same. This phenomenon has created the mistaken belief that a customer using less energy reduces the utility's cost to serve that customer – instead of simply a lower utilization of fixed assets that must remain ready to serve that customer.

I further detail how UNS Electric is proposing a three-part rate design that adds a demand charge to the basic service charge and the energy charge. Specifically, the demand charges would recover fixed costs allocated to the customer's class based on the amount of the system they use and when they use it. This rate structure would more accurately reflect the cost of providing service while maintaining consistency with the Company's rate design objectives. I list the precedent for three-part rate designs to residential customers. I also explain that such a design (all of its three components) will provide proper price signals so that customers can make informed choices about energy usage. In my testimony, I detail the specifics of the Company's proposed three-part rate proposals for residential (RES-01 Demand and RES-01 Demand TOU) and small commercial (SGS-10 Demand and SGS-10 Demand TOU) customers. I also provide the rate impacts using several average energy (kWh) usages. Ultimately, I explain how the three-part rate rewards customers who improve their load factor consistent with more efficient use of the electric utility system – and how it is not the case that residential customers with very low usage will necessarily benefit less from such a structure.

Even so, the Company is not proposing to move all residential and small-commercial customers to a three-part rate structure in this case. With regards to the two-part rate structure, UNS Electric proposes to increase the basic service charge to a level much closer to the appropriate minimum system-cost level. The Company also seeks to remove one of the rate tiers from the standard residential rate (RES-01). Specifically, UNS Electric seeks to increase the Basic Service Charge to $20.00 per month for tariff RES-01, Residential Service – while having only two tiers in the volumetric Delivery Services-Energy charges (0-400 kWh and usage over 400 kWh). The Company's proposals here will begin the move toward a more balanced rate structure that addresses the issues I have highlighted above.

Regarding the Company's proposal for the adoption of a new net-metering rider, that rider will only apply to net metering DG customers that submit a completed application for interconnection to UNS Electric's grid facilities after June 1, 2015. Existing net-metering DG customers and those with interconnection applications submitted before June 1, 2015 (and ultimately approved) will stay on the current rider for up to 20 years from the date of approval. New net metering DG customers, in the meantime, would be compensated for any excess energy with a bill credit at the Renewable Credit Rate. Further, the Company will purchase excess energy from the DG customer during the billing cycle (that is, eliminating the banking option). This is a further step to send more accurate price signals to net metered customers about their true energy costs. Still, DG customers still see a significant savings on their electric bill, as I show through an example I detail later in my testimony. In other words, the new net-metering rider reduces, but does not eliminate, the subsidy provided to applicable DG customers.

I also explain that, since DG customers with net metering are partial requirements customers, the current two-part rate design options are ill-equipped in accounting for how

these customers use UNS Electric's system. This is because two-part rates are designed to recover costs based on average consumption levels for full-requirements customers. So, it is appropriate to require all DG customers to be on a three-part rate schedule. While further mitigating the cost shift I describe in preceding paragraphs, I show how DG customers still save on their total electric bill. These customers can also reduce bills through decreasing billing demand or energy usage.

Finally, I discuss the Company's proposal for an Economic Development Rider. Because UNS Electric's service territory has been very slow to recover and because it has lost several of its largest customers (resulting in fewer sales) this rider together will help put the UNS Electric service territory in a better competitive position to attract and expand business load. The EDR will be available to customers with projected peak demand of 1,000 kW or more and a load factor of 75% or higher and for five years from the effective date – providing discounts on monthly electric bills according to a declining schedule. Potential participants must meet several criteria to qualify and the discounts will only apply to the qualifying additional loads from business expansion or retention – with total program participation limited to 50 MW. I detail the criteria and further describe the discounts to qualifying customers in the last section of my testimony.

II. REQUESTED REVENUE INCREASE.

Q. What is the overall revenue increase being requested by UNS Electric?

A. 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 Transmission Cost Adjustor. 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 Deferred 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%

III. RATE DESIGN.

A. Overview.

Q. Is UNS Electric proposing changes to its residential, commercial, and industrial rates?

A. Yes. I will be discussing the more significant rate changes that UNS Electric is proposing for the residential and small commercial customer classes. UNS Electric witness Craig Jones will be discussing other proposed rate design changes.

Q. What are the rate design changes UNS Electric is proposing?

A. To better align rate design with cost-causation and to reduce inter-class inequities, UNS Electric is proposing the following changes for the residential and small commercial (small general service) rate classes:

- Increase the basic service charge to $20 for standard residential customer rates (Rates RES-01, RES-01 TOU, RES-01 TOU SP).
- Increase the basic service charge to $30 for small general service customer rates (Rates SGS-10, SGS-10 TOU).
- Eliminate one of the volumetric rate tiers from standard residential customer rates (Rates RES-01).
- Offer two three-part rate structure options to all customers meeting the applicability requirements for the residential and small general service rate classes.
- Freeze and grandfather the current Rider-4 (Net Metering for Certain Partial Requirement Services (NM-PRS)), Pre June 1, 2015. Rider-4 will have a proposed expiration date of May 31, 2035.

- Create a new Rider-10 (NM-PRS), Post June 1, 2015, that discontinues the banking of kilowatt-hours ("kWh") but allows a net metered customer to: (i) continue to offset energy consumption with energy production at the retail rate and (ii) sell excess energy production to UNS Electric at the Renewable Credit Rate as described in the testimony of Carmine Tilghman.
- Require partial requirement customers qualifying for the new Rider-10 to choose from one of the two proposed three-part rate tariffs applicable for their service requirement.

Q. What are the guidelines or criteria adhered to in evaluating its proposed rate design modifications?

A. UNS Electric is generally following the principles outlined over five decades ago by Professor James C. Bonbright in his work, "Principles of Public Utility Rates," which was reissued in its second edition in 1988. While Professor Bonbright's "Principles" go back five decades, they continue to serve as the foundation for reasonable rate design objectives.

Q. What are those foundational principles?

A. They are as follows:

- The related "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
- Freedom from controversies as to proper interpretation.
- Effectiveness in yielding total revenue requirement under the fair-return standard.
- Revenue stability from year to year.
- Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers.

- Avoidance of "undue discrimination" in rate relationships.
- Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use.

Q. Is there one principle in rate design that is foundational or primary?

A. Yes. The principle of cost-causation, i.e. rates should reflect cost based recovery. The further away you get from this fundamental foundation, the closer you get to unduly burdensome and discriminatory rate structures that allow for both intra- & inter- class subsidization.

Q. Have fundamental changes occurred in the utility industry since Bonbright's principles were formulated?

A. Yes. At the time Bonbright's principles were formulated the utility industry was typically experiencing steady year-over-year growth in kWh sales and expanding its generation, transmission and distribution systems. In addition, customers had little to no options for alternative power supplies or the ability to control their demand on the expanding utility systems.

However, today there is a growing market of energy efficiency, distributed generation and demand response options available to our customers. New digital metering technology and communication applications also allow today's electrical customers to monitor how and when they use power and the grid.

These factors have contributed to flat or declining kWh sales. Rooftop solar and net metering have become significant factors, especially in Arizona, including UNS Electric's service territory. So the discussion of appropriate pricing and incentive structures has become more complex and necessary as it is a much more important issue.

Q. What do you mean by appropriate pricing structures?

A. To address that, I first need to discuss the cost structure of UNS Electric. The majority of utility costs are fixed – that is, they do not vary with usage. In the case of UNS Electric, its fixed costs stem from investment in and maintenance of equipment and infrastructure and the salaries of employees that are needed to provide safe, reliable power regardless of individual customers' kWh consumption.

Like any electric utility, UNS Electric must do so to meet the potential maximum demand of every customer. It would be cost prohibitive and economically unsound to invest in an electrical system scaled differently to meet the unique and constantly changing demands of each individual customer.

The Company has an obligation to invest in and maintain an infrastructure that is capable of meeting these maximum potential demands of every customer in its service territory. For that reason, UNS Electric incurs essentially the same costs to serve a residential customer who uses 10 kilowatts ("kW") for ten hours per month (100 kWh) as it does to serve a neighbor who uses 10 kW for 100 hours per month (1,000 kWh). The only completely avoidable cost is the variable cost related to the energy production, primarily fuel, purchased power and any O&M costs directly related to energy production or procurement.

Q. Are UNS Electric's residential & small commercial pricing structures presently designed appropriately based on the principal of cost causation?

A. No. The Company's current rate design for residential and small commercial customers does not reflect the way costs are incurred to serve the customers within these classes. For decades, rate designs for these classes have incorporated a very simplistic two part rate structure; a basic service charge (customer charge) and energy charges. This was

defensible because these customers typically had relatively similar usage levels and patterns. It also allowed utilities to avoid the higher cost of meters capable of measuring demand.

Historically, basic service charges have been limited to bare minimum levels while inclining price rate tiers have been added, forcing customers who use more power to pay an increasingly disproportional share of the fixed costs incurred on behalf of all customers. Today, though, customers have access to a burgeoning market of distributed energy resources ("DER") and demand management opportunities. The growing inequities that result from these new options are exacerbated by utility rates that have become even more inequitable. Thus, UNS Electric is proposing rate design changes that are designed to address those inequities.

As I described above, customers' individual kWh consumption is not indicative of the fixed costs they impose on their utility. A few examples to illustrate this point are summarized below.

- Seasonal Customers. Portions of UNS Electric's service territory have many customers who only live in their homes for just part of the year. Under the Company's current rates, these customers only pay a portion of the fixed costs associated with providing safe, reliable service to their homes.
- Vacant homes or businesses. Vacant homes and unoccupied apartments with little to no consumption generate far less revenue for UNS Electric than is needed to cover the fixed costs they impose on the Company.
- Distributed Generation ("DG") Customers. Customers with DG power systems still rely on UNS Electric to supply the full potential kW requirements of their home whenever they need it. These customers also need the local distribution grid to support the reliable operation of their systems and to accept any excess

power they generate. While UNS Electric must provide the infrastructure to address these needs, it cannot recover the cost of these services from DG system users under current rates, which rely heavily on energy charges to recover fixed costs. This inequity is exacerbated by net metering, which allows customers to "bank" their systems' excess energy for free and exchange it for on-demand service from their utility.

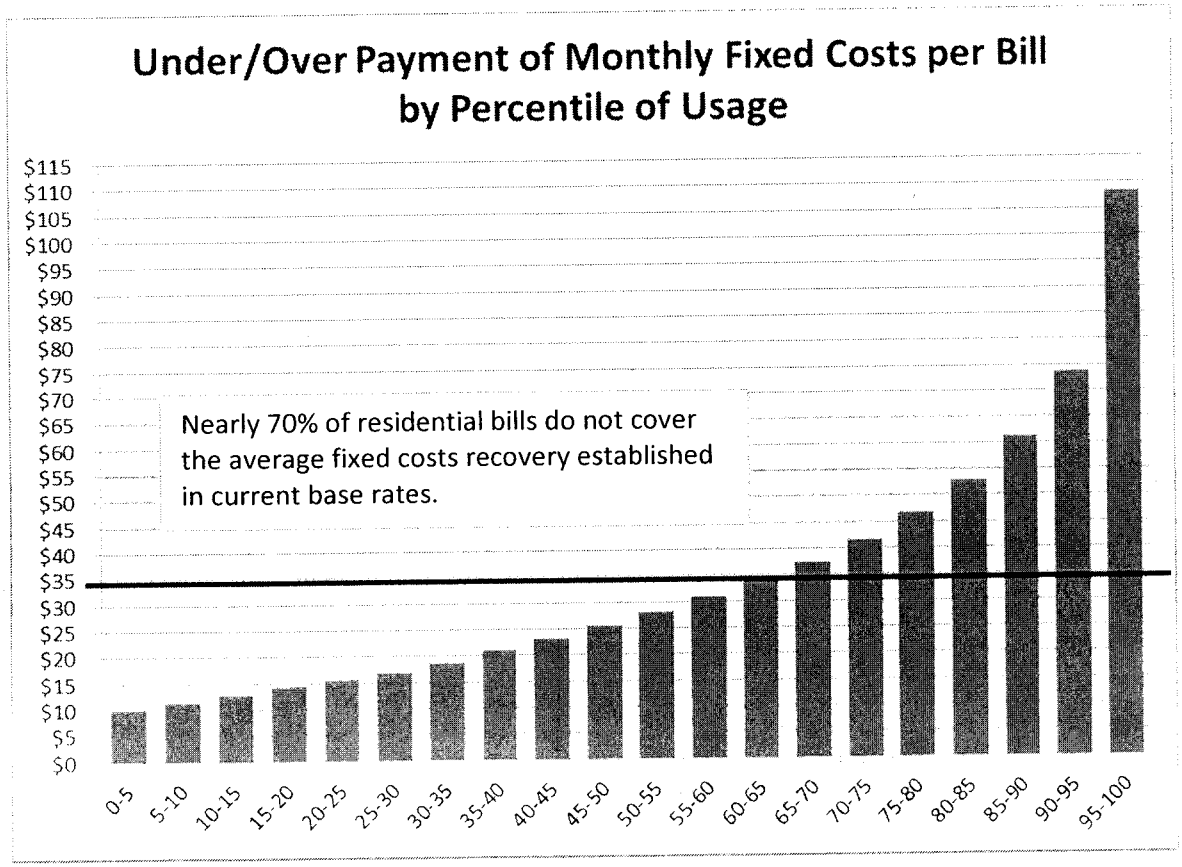
The situations described above limit UNS Electric's ability to recover its fixed service costs. Nearly one out of every four residential (Residential RES-01) bills issued by UNS Electric during the test year – 205,129 to be precise – reflected usage of 300 kWh or less. Because even a studio apartment with basic appliances and moderate usage would likely consume at least 400 kWh per month, these bills probably were generated by vacant homes, seasonal customers and DG customers. UNS Electric recovered only $10 to $16 in fixed costs per month from these customers – two to three times less than their fair share of the fixed costs the Company incurs to provide service on their behalf. Those fixed costs are described in more detail in the testimony of UNS Electric witness Craig Jones.

In future rate filings those unrecovered costs would be shifted to other customers under the present volumetric rate design. Another way to look at it is: if each of those bills would have recovered just the test year average fixed cost recovery for the residential class of $35, the additional cost recovery would at a minimum have been an additional $4 million. That is more than UNS Electric's approved revenue increase in its last rate decision and more than the net requested rate increase in this proceeding.

Q. Does the inclining block rate structure also contribute to these intra-class inequities?

A. Yes. As discussed above, kWh consumption doesn't directly correlate with how much of the system a customer may require at any point in time.

UNS Electric recovered, on average, $35 in fixed costs per bill from residential customers during the test year. As shown in the chart below, though, approximately two-thirds of the bills issued in the last 4 years to residential customers (applying the current RES-01 rate) did not provide fixed cost recovery equivalent to the class average established in the most recent rate decision. This means that about one-third of residential customers' bills recovered above average amounts of fixed costs, while two-thirds recovered below average amounts. There is no cost basis for such a disparity and as such this structure is unduly burdensome and unequitable to the higher consumption users.



Because we've been billing this way for so long, we've sent improper price signals to our customers. Customers have been led to believe that if they use less energy during a particular billing period, their utility's costs are reduced by a comparable amount. But such reductions simply result in lower utilization of fixed utility assets that must remain at the ready to power every light, appliance, fan, air conditioner, computer, television and other equipment their customers might choose to use.

Q. Has UNS Electric experienced a reduction in energy sales and use-per-customer ("UPC") for the residential and small commercial rate classes?

A. Yes, Since 2007 UNS Electric has seen a decline of 8% in its UPC in just the residential customer class alone.

Q. What do you believe is driving these reductions?

A. There are several factors contributing to lower consumption, including: adoption of energy efficiency measures; more energy efficient building codes and appliance standards; increased use of distributed generation; challenging economic conditions; and other conservation efforts by UNS Electric's customers.

Q. Have these sales and UPC reductions resulted in lower costs for customers?

A. On the whole, they have not. While individual customers have enjoyed lower bills due to energy efficiency and DG systems, their bill savings have not resulted in equivalent system demand reductions. The level of investment and maintenance required to meet customer demand has not been reduced; rather, the burden of paying for it has been shifted from customers who use less energy to those who use more.

Q. Why is it important to distinguish between system savings and individual savings?

A. UNS Electric witnesses Craig Jones and Carmine Tilghman will provide more detail about the cost drivers associated with the electric distribution system and the relationship with peak demand. Broadly speaking, though, the distribution system is a network designed primarily to meet the non-coincidental peak demands of customers. The transmission and generation systems, by contrast, are designed to meet the coincidental peaks of the distribution system, with reserves and margins for growth and planning purposes.

When customers reduce their energy consumption through temporary vacancies or intermittent solar DG systems, their peak demand typically does not change. In the case of DG customers, it could even grow as a result of oversized generating facilities being added to maximize energy production; that is further discussed in the testimony of Carmine Tilghman.

So while customers enjoy bill savings from their reduced usage, the Company's fixed system costs for distribution service are not reduced. System savings can be realized in future years through reductions in the system's coincidental peak demand. So customers need to be given the proper price signals and incentives through rates to promote those beneficial changes.

Q. How could residential and small commercial rates be structured to most accurately reflect the costs of providing electric service?

A. The closest rate structure from a cost recovery only basis is a straight fixed-variable ("SFV") design. Under this method, the monthly basic service charge recovers all fixed service costs, while variable charges reflect those costs directly tied to energy usage.

Q. Is UNS Electric proposing SFV rates in this proceeding?

A. No. Adoption of strict SFV rates would result in dramatic rate increases for customers at lower kWh consumption levels and not provide adequate price signals to customers to reduce their impacts on the electrical system. This is not consistent with the Company's rate design objectives and would violate the utility ratemaking principal of gradualism.

Q. What type of rate structure would more accurately reflect the cost of providing service and also be consistent with the Company's rate design objectives?

A. A three-part rate design consistent with those presently employed for larger customers would be more appropriate and provide a balance between fixed cost recover, cost causation and price signals incenting more efficient use of the utility system.

Q. How would costs be recovered through the three-part rate design proposed by the Company in this proceeding?

A. Three-part rates, incorporate the following components:

- **Basic Service Charge** – To recover fixed costs directly attributable to the customer, including the meter, service line, on-site equipment, meter reading and equipment, customer support and billing and minimum distribution system cost.
- **Demand Charges** – To recover fixed costs allocated to the customer's class based on the amount of the system they use and when they use it.
- **Energy Charges** – To recover variable costs directly attributable to the customers' energy use.

Q. Do any utilities use three-part rates for residential and small commercial customers?

A. Yes. At least eight utilities offer three-part rates to residential customers in at least 9 states:

1. Alabama Power (Alabama)
2. **Arizona Public Service ("APS")** (Arizona)
3. Black Hills (South Dakota, Wyoming)
4. Dominion (Virginia, North Carolina)
5. Duke Energy (North Carolina, South Carolina)
6. Georgia Power (Georgia)
7. **Salt River Project** (Arizona)
8. Xcel Energy (Colorado)

In Arizona, APS' optional residential three-part rate has been in effect since the 1980's. Approximately 10 percent of that company's residential customers use that rate.

Q. Why does UNS Electric prefer that all customers use three-part rates?

A. Three-part rates more fairly allocate costs to the customers within a class that "cause" them and provide proper price signals that help customers make informed decisions regarding their energy and electrical system usage. Three-part rates also reward customers for better load factors and reductions in peak usage – attributes that lead to lower system costs, which benefits all customers.

The Basic Service Charge should be designed to recover the average unavoidable fixed costs that utilities incur each month. It should provide customers with a more accurate price signal that reflects the costs incurred to assure minimum service from the electrical grid to provide safe and reliable service.

Similarly, the Demand Charge should provide customers with a price signal that accurately reflects the cost of system resources that must be available to serve their individual peak load. They then can make proper usage and equipment purchase decisions that would reduce that portion of their bill while producing system benefits.

Finally, Energy Charges should reflect costs that are entirely avoidable when energy consumption is reduced.

B. Proposed Changes to the Standard Two-Part Rates.

Q. Is UNS Electric requesting that all residential and small commercial customers be migrated to a three-part rate structure?

A. Although UNS Electric is proposing a three-part rate structure as an option, it is not proposing to require all residential and small commercial customers to migrate to a three-part rate structure. Presently, UNS Electric doesn't have the capability to measure demand for every customer and is not advocating a forced migration to such a structure at this time. UNS Electric is requesting to begin moving toward a more balanced rate structure that would make such a move possible in the future.

Q. What are reasonable steps that can be taken in this proceeding to begin this transition?

A. For the standard residential and small general service rates, we can start by moving the basic service charge much closer to the appropriate minimum system cost recovery level. In addition, we can remove one of the rate tiers from the standard residential rate. These changes will provide for more equitable recovery of fixed cost and reduce intra-class subsidization. The Company is proposing these changes at a level that it believes will provide for significant improvement of the rate structures without undue rate shock.

Q. What changes specifically are you requesting for residential customers?

A. For tariff RES-01, Residential Service, we are requesting an increase in the Basic Service Charge to $20.00 per month. The Company is also requesting the elimination of the third tier in the volumetric Delivery Services-Energy charges. In other words, the RES-01 will

have one tier from 0 – 400 kWh and another for all usage over 400 kWh. The respective charges for the two tiers will be $0.030810 per kWh for the first 400 kWh and $0.050810 per kWh for all remaining kWh.

C. Net Metering Rider Modifications.

Q. Is UNS Electric requesting changes to its net-metering tariffs? What changes are you proposing for customers qualifying for Net Metering?

A. Yes. We are proposing the adoption of Rider-10, Net Metering for Certain Partial Requirements Service (NM-PRS), Post June 1, 2015. The Company's proposed net metering tariff is described in the testimony of Carmine Tilghman. The applicable three-part standard offer tariffs will be mandatory for Net Metering customers taking service under this Rider.

Q. Will Rider-10 apply to all Net Metering customers?

A. No. Rider-10 will only apply to Net Metering customers that submit completed application for interconnection to UNS Electric's grid facilities after June 1, 2015. All currently existing Net Metering customers and those with completed interconnection applications that were submitted prior to or on June 1, 2015 (and ultimately approved) will stay on the Net Metering Rider-4 for a period not to exceed twenty years. UNS Electric is proposing that the Rider-4 expire no later than May 31, 2035.

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 current 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. What is the Renewable Credit Rate and how is it developed?

A. The Renewable Credit Rate is the price at which UNS Electric will compensate customers with DG for the excess energy produced by the customer's generation facility as discussed in Carmine Tilghman's testimony.

Q. If adopted, what issues will be remedied by UNS Electric's Net Metering tariff proposal?

A. First, eliminating the banking option for excess energy production will no longer give DG customers the impression that their excess energy can be stored on UNS Electric's system for future use. By simply purchasing the excess energy from the customer during their billing cycle, as opposed to allowing customers to use the kWh credits at a later time, UNS Electric will send more accurate price signals to Net Metered customers about their true energy costs.

Second, eliminating the banking option helps to partially alleviate the bypass of fixed cost recovery that occurs when customers self-generate a portion of their energy requirements. The bypass of fixed cost recovery by DG customers can be illustrated with an example.

The table below presents the average monthly fixed cost recovery and average pre-tax monthly bills using UNS Electric's proposed rates for three types of residential customers at monthly electric usage levels of 500 kWh, 900 kWh, 1,200 kWh, and 1,500 kWh. The three customer types all take service under standard offer tariff RES-01 and the bills in this table are calculated with the RES-01 rates proposed in this application. The first case

is a customer with no DG, the second a DG customer with Net Metering and banking of excess kWh, and the third a DG customer with Net Metering and utility purchase of excess kWh as proposed in this application. The DG customers have solar PV systems sized to produce a kWh output that would yield zero excess kWh on an annual basis and the load profiles for each customer size are from actual UNS Electric customer data.

Monthly Usage	No DG	Net Metering with Banking of Excess kWh	Net Metering with Purchase of Excess kWh
500 kWh per Month			
Monthly Fixed Cost Recovery	$37.61	$20.20	$28.88
Average Monthly Bill (pre-tax)	$63.79	$23.38	$28.22
Unrecovered Fixed Costs	NA	$17.41	$8.73
Monthly Bill Savings	NA	$40.41	$35.56
900 kWh per Month			
Monthly Fixed Cost Recovery	$57.72	$20.34	$37.27
Average Monthly Bill (pre-tax)	$102.05	$23.55	$33.93
Unrecovered Fixed Costs	NA	$37.38	$20.45
Monthly Bill Savings	NA	$78.50	$68.12
1,200 kWh per Month			
Monthly Fixed Cost Recovery	$72.97	$20.39	$44.61
Average Monthly Bill (pre-tax)	$130.93	$23.62	$39.33
Unrecovered Fixed Costs	NA	$52.58	$28.36
Monthly Bill Savings	NA	$107.30	$91.60
1,500 kWh per Month			
Monthly Fixed Cost Recovery	$88.20	$20.61	$52.85
Average Monthly Bill (pre-tax)	$159.76	$23.89	$45.46
Unrecovered Fixed Costs	NA	$67.58	$35.35
Monthly Bill Savings	NA	$135.87	$114.31

In this example, a residential customer on RES-01 using 900 kWh per month and no DG system would pay an average of $57.72 per month in fixed costs. The fixed cost recovery in this case consists of the fixed Basic Service Charge and the variable Delivery Services-Energy charges at that level of consumption. By contrast, the same customer with a DG system that produces the same annual kWh as consumed pays an average of $20.34 per

month if allowed to bank kWh produced in excess of usage at any time in order to offset consumption at a later time. This results in a fixed cost recovery shortfall of $37.38. With a $20.00 per month Basic Service Charge, this customer is paying only $0.34 per month above the Basic Service Charge for the fixed costs associated with the generation capacity, transmission, and distribution infrastructure provided to serve the customer.

The same DG customer under the regime where UNS Electric purchases the excess kWh generated as proposed in this filing pays $37.27 in fixed costs. In this case UNS Electric recovers $16.93 more of its fixed costs than under the banking scheme, but is still $20.45 short of the fixed costs recovered from the non-DG customer. Keep in mind that the $16.93 in fixed costs that is bypassed using the banking scheme, like the utility infrastructure it is paying for, does not go away. It will ultimately have to be recovered from the other customers on the system who are not Net Metering customers. Because UNS Electric purchases the excess kWh production, there are now $16.93 less in fixed costs that must be recovered from customers without Net Metering.

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

A. Under this proposal, DG customers would still see significant savings on their electric bills. In the example above, the monthly pre-tax bill savings for a Net Metering customer using 900 kWh per month is reduced by $10.38, from $78.50 to $68.12. This is still a 67% reduction in that DG customer's monthly electric bill.

Q. Will this change to UNS Electric's treatment of Net Metering completely eliminate the shifting of fixed costs due to DG?

A. No. The adoption of the new net-metering rider, which no longer allows for energy banking, will reduce but not eliminate the subsidy. However, when combined with the

proposed standard offer three-part tariff, the magnitude of cost shifts to non-DG customers will be greatly reduced.

Q. Why is UNS Electric proposing that new Net Metering customers be required to take standard offer service on a three-part tariff?

A. As I mentioned earlier, the proposed Net Metering changes will not fully mitigate the DG cost shift. The DG customers' usage patterns and load profiles are no longer those of a full requirements customer – in which the standard volumetric rate is designed to recover cost based upon. They are partial requirement customers and as such the three-part rate design is more appropriate. The three-part rate design is presently the Commission approved structure for UNS Electric's partial requirement customers in the larger rate classes.

The cost shift is also increased by the fact that a majority of the fixed costs to serve residential and small commercial customers are recovered through variable energy usage charges. These usage based charges have built in rate tiers that charge more for usage when a customer's consumption reaches each subsequent threshold. Assuming that fixed costs can fairly and equitably be recovered primarily through volumetric rates ignores the ever <u>increasing</u> magnitude of the cost shift created by DG customers, as well as energy efficiency and conservation.

DG customers avoid paying a substantial portion of their fixed costs of the system by avoiding these higher consumption levels. When the energy produced by a DG system is used by the customer and netted against the energy that would be delivered by the utility, the fixed costs embedded in the variable utility charges go unrecovered. Furthermore, the recovery of these fixed costs is being avoided primarily at the higher tier rates in the inverted block rate structure.

D. Three-Part Rate Proposals.

Q. Please summarize UNS Electric's new three-part rate proposals for residential customers.

A. For the residential class, UNS Electric is proposing RES-01 Demand and RES-01 Demand TOU. For RES-01 Demand, we are proposing the same $20.00 per month Basic Service Charge that we are proposing for RES-01. Also, we are proposing a two-tier monthly Demand Charge with the break point at 7 kW. Billing demand will be based on the 1-hour maximum measured demand during the billing month. The Delivery Service-Energy charges have a single tier and are reduced significantly from those in RES-01 to reflect the fixed cost recovery being more properly recovered through the demand charges. All other charges are identical to those in RES-01. For RES-01 Demand TOU, the Basic Service, Demand, Delivery Services-Energy, and all other charges except Base Power are the same as those for RES-01 Demand. The Base Power Charges vary by time of use.

Q. How would the proposed three-part rates impact residential customer bills?

A. The table below shows average monthly bills (pre-tax) for residential customers using an average of 500 kWh, 900 kWh, 1,200 kWh, and 1,500 kWh. The customers in this example are full-requirements customers taking service under RES-01 and RES-01 Demand at proposed rates. The following customer examples were developed from UNS Electric's residential customers' usage data. It is evident from the comparisons presented in this table that customers at the lower end of the usage spectrum pay higher monthly bills on the three-part rate than on the two-part rate.

Bills calculated using the three-part rate will exceed bills using the two-part rate at lower levels of consumption. As usage increases, customers on the three-part tariff will have lower monthly bills.

Average Monthly Usage	Average Monthly Load Factor	Average Monthly Bill		
		RES-01	RES-01 Demand	Difference
500 kWh	19.4%	$70.16	$79.66	$9.49
900 kWh	22.4%	$112.26	$116.94	$4.68
1,200 kWh	25.0%	$144.02	$142.59	($1.43)
1,500 kWh	27.0%	$175.74	$170.38	($5.36)

Q. From this information, can one conclude that residential customers with very low usage will benefit less from a three-part rate than higher usage customers?

A. No. One other piece of information in this table is the average monthly load factor for each customer profile. Load factor is a concept that indicates how a customer is using energy relative to the peak demand that the customer incurs. One commonly used definition of the load factor is the average demand over a period divided by peak demand. By this definition as average demand increases relative to peak demand, the load factor increases. It also follows that as a customer uses more energy, i.e., more kWh, for any given peak demand, the load factor increases. It is generally accepted that a higher load factor implies a more efficient use of the utility system.

The load profiles used for these bill comparisons were developed from 2014 UNS Electric residential customer load data. One trend that is evident is that higher usage customers generally have higher load factors. As shown in the table above, the lower usage customers on the three-part rate see a negative impact, which decreases and becomes a positive benefit at higher usage levels. This occurs because the load factor is increasing not peak usage. The higher usage customers are using more kWh per kW than lower usage customers. As I mentioned earlier, Delivery Services-Energy charges in the three-part rate are approximately 70% lower than those in the two-part rate and the benefits of the lower per kWh charges begin to take over as load factor increases.

Q. What can one conclude from these results?

A. The three-part rate with a demand charge rewards customers with higher load factors, all else equal. More important, a three-part rate will reward customers who improve their load factor. If residential customers choose to take service on a three-part rate they will reduce their electric bills by improving their load factor or maintaining a higher load factor. As I mentioned earlier, higher load factors are consistent with more efficient use of the electric utility system. Under a three-part rate, customers receive a price signal encouraging them to improve their load factor, which benefits the customer by reducing their electric bills and benefits all UNS Electric customers as the system is used more efficiently.

Q. Are there other ways customers can benefit from a three-part rate design?

A. Absolutely. Customers continue to have more options to save in the future when technology can help them manage and reduce demand. As a simple example, consider someone with two air conditioning units, a pool pump and an electric water heater. That person (or UNS Electric through energy efficiency programs) could invest in systems that prevent all four appliances from coming on at one time. The units are cycled and thus the impact on the system and their demand charge is reduced as it relates to those pieces of equipment. These types of control systems are currently available and properly designed rate structures and customer education programs could lead to more installations and system benefits, by providing the proper economic incentive.

Q. Could a three-part rate structure for residential and small commercial customers encourage development of business models and customer applications aimed at reducing customers' individual demand?

A. Yes. A three-part rate structure will provide customers pricing options that could lead to earlier adoption of new energy technologies. For example, UNS Electric and other

companies will be incentivized to combine technologies like solar panels, energy storage and demand control systems to maximize customer savings and profitability of their programs.

Q. Please summarize UNS Electric's new three-part rate proposal for small commercial customers.

A. The small commercial three-part rate tariffs UNS Electric is proposing are SGS-10 Demand and SGS-10 Demand TOU. We are proposing a Basic Service Charge of $30.00 per month for a SGS-10 Demand and a two-tiered Demand Charge with a break point at 15 kW. The second tier in the SGS-10 Delivery Service-Energy charges has been removed for the three-part rate and the energy charges are reduced significantly to reflect the fixed cost recovery being more appropriately recovered through demand charges. For SGS-10 Demand TOU the Basic Service, Demand, Delivery Service-Energy, and all other charges except Base Power are the same as those for SGS-10 Demand. The Base Power Charges vary by time of use.

Q. Is UNS Electric proposing that all residential and small commercial customers take service on three-part rate tariffs?

A. No. At this time UNS Electric is proposing three-part rate tariffs as optional for residential and small commercial customers who are not taking service under the Net Metering Rider-10. All residential and commercial Net Metering Rider-10 customers will be required to take service under the applicable three-part standard offer tariff.

E. **Partial Requirements Customers.**

Q. **In your summary you state that UNS Electric is proposing that partial requirement customers qualifying for the new Net Metering Rider-10 must choose from one of the two proposed three-part rate tariffs applicable for their service requirement. Why is UNS Electric proposing to require these customers to use a three-part rate tariff?**

A. Simply stated, the Company's current two-part rate design options do not account for how these customers use the system and will never properly recover a fair level of fixed costs. **The two-part rates are designed to recover costs based on the average consumption levels of full-requirements customers** - and as presently designed and proposed rely on energy charges to recover fixed cost. Also as discussed above, even with the changes we are proposing to our present full requirement tariffs (higher Basic Service Charge and elimination of a tier) – these new rates will continue to recover the majority of fixed cost through volumetric energy rates.

Q. **Do UNS Electric's proposed three-part rates for partial-requirements residential and small commercial customers further mitigate the DG cost shifting covered earlier?**

A. Yes. The table below presents monthly fixed cost recovery and average monthly electric bills for the same four residential customer profiles that I presented earlier. The examples in this case are for a full-requirements residential customer on RES-01 at proposed rates and two partial-requirements Net Metering customers, one on the proposed RES-01 two-part rate and the other on the proposed RES-01 Demand three-part rate. In both of the Net Metering cases, UNS Electric is purchasing the excess output of the DG system at the Renewable Credit Rate.

As is evident from the results in this table, the three-part rate goes a long way toward further mitigating the DG cost shift. For the 900 kWh per month customer I discussed earlier, only $0.34 per month in fixed costs is now bypassed. Furthermore, the customer is still saving $47.90 per month on their total electric bill, which is a savings of 47%. Even the low-usage customer at 500 kWh per month, while paying $6.17 per month more in fixed costs than the full-requirements customer, is saving $20.58 per month on the total electric bill, a savings of 32%. For the larger 1,500 kWh per month Net Metering customer on the proposed three-part rate total monthly bill savings are 57%.

Monthly Usage	RES-01 - Full Requirements	RES-01 - Net Metering	RES-01 Demand - Net Metering
500 kWh per Month			
Monthly Fixed Cost Recovery	$37.61	$28.88	$43.78
Average Monthly Bill (pre-tax)	$63.79	$28.22	$43.21
Unrecovered Fixed Costs	NA	$8.73	($6.17)
Monthly Bill Savings	NA	$35.56	$20.58
900 kWh per Month			
Monthly Fixed Cost Recovery	$57.72	$37.27	$57.38
Average Monthly Bill (pre-tax)	$102.05	$33.93	$54.15
Unrecovered Fixed Costs	NA	$20.45	$0.34
Monthly Bill Savings	NA	$68.12	$47.90
1,200 kWh per Month			
Monthly Fixed Cost Recovery	$72.97	$44.61	$65.18
Average Monthly Bill (pre-tax)	$130.93	$39.33	$60.02
Unrecovered Fixed Costs	NA	$28.36	$7.79
Monthly Bill Savings	NA	$91.60	$70.91
1,500 kWh per Month			
Monthly Fixed Cost Recovery	$88.20	$52.85	$75.49
Average Monthly Bill (pre-tax)	$159.76	$45.46	$68.23
Unrecovered Fixed Costs	NA	$35.35	$12.71
Monthly Bill Savings	NA	$114.31	$91.53

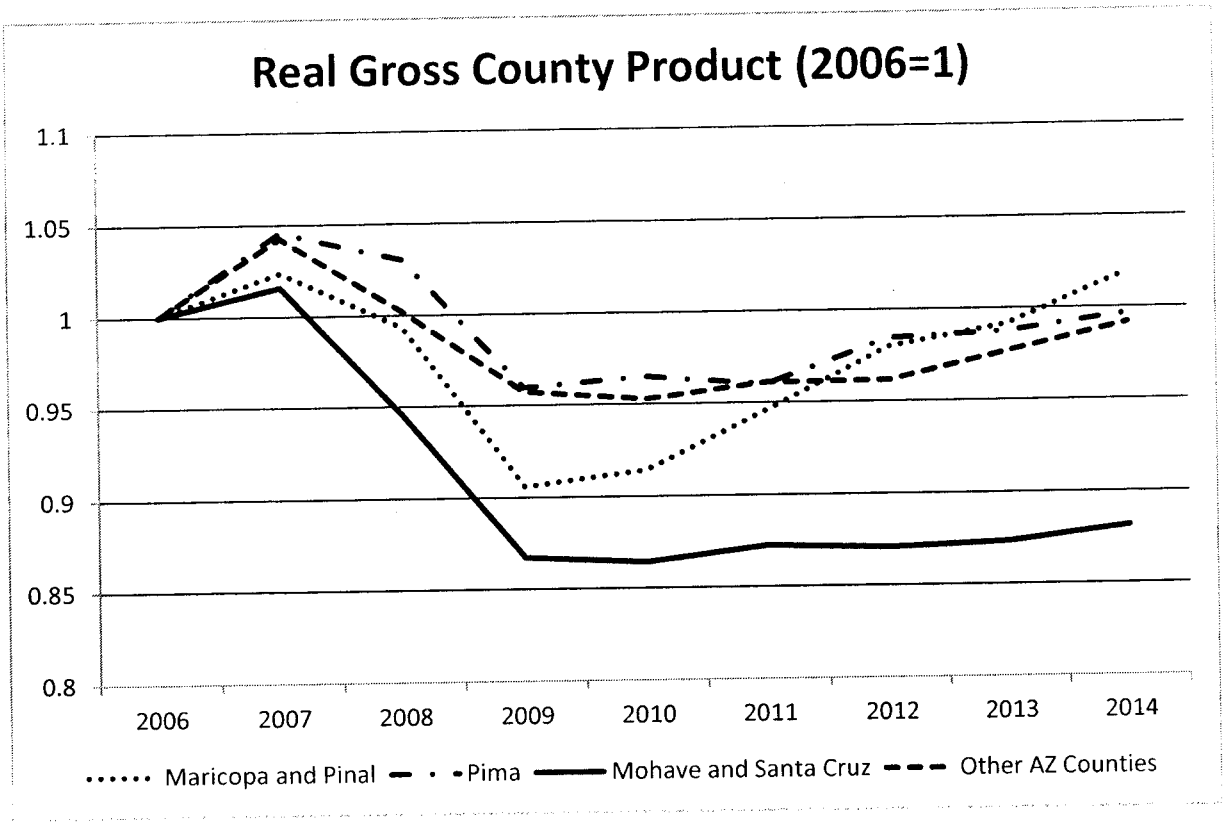
Q. You showed how residential DG customers with Net Metering will continue to see significant bill savings on the proposed three-part tariff. Are there any other opportunities for these customers to lower their monthly bills and realize added savings?

A. Yes. The incentive still exists for DG customers to reduce bills by decreasing billing demand or energy usage. However, because volumetric energy charges embodied in the three-part rate are much lower than those in the two-part rate, the potential savings from reduced energy use are not as high as those from reducing peak demand. Regardless, peak demand reductions that are greater than energy use reductions on a percentage basis will yield a higher load factor and provide benefits to the customer and the electric system.

F. <u>Economic Development Rider.</u>

Q. Why is UNS Electric proposing an Economic Development Rider in this proceeding?

A. The UNS Electric service territory has been very slow to recover from the economic downturn post 2007 and has also lost several of its largest customers in the past few years. Both of which has resulted in fewer sales units to spread the fixed cost of the system over and thus more cost being allocated to the remaining customers. I've already discussed the declining sales in the UNS Electric service territory and those impacts on customers' bills. Below is a chart showing the recovery of Real Gross County Product for Maricopa, Pinal, Pima and other Arizona counties – as opposed to the UNS Electric service counties, Mohave and Santa Cruz - these two counties have seen little to no improvement since 2009.



Q. Do you believe an Economic Development Rider could assist business growth in these areas?

A. Yes. The inclusion of this additional incentive along with the rate design changes discussed in UNS Electric witness Craig Jones' testimony, reducing rates for the business classes - should put the UNS Electric service territory in a better competitive position to attract and expand business load. This would be beneficial to the entire customer base and the State of Arizona.

Q. Please describe UNS Electric's proposed Economic Development Rider.

A. UNS Electric is proposing to offer Rider 13, Economic Development Rider ("EDR") to current or potential commercial and industrial customers that meet certain economic development criteria within the UNS Electric service areas. The EDR will be available to customers with a projected peak demand of 1,000 kW or more and a load factor of 75% or higher. The EDR will be available for five years from the effective date and provides

qualifying customers with discounts on monthly electric bills according to a declining schedule over a five-year period at which point the discount is terminated. The discounts will apply only to the qualifying additional loads from new or expanding business operations and total program participation will be limited to 50 MW of applicable load.

Q. What are the qualifying criteria for the proposed EDR?

A. In addition to demand and load factor, customers must meet several criteria to qualify for the proposed EDR. First, potential EDR customers must qualify for at least one of two Arizona state tax credit programs designed to promote business recruitment, retention, and expansion. Arizona's Quality Jobs Tax Credit (A.R.S. § 41-1525) program provides a tax credit for net increases in full-time employees residing in the state and hired in qualified employment positions. The Qualified Facility Tax Credit (A.R.S. § 41-1512) program provides for a refundable tax credit for qualifying capital investment in a manufacturing facility that creates new jobs paying at least 125 percent of the median county wage and covering at least 80 percent of employee's health care premiums.

Q. Please describe the discounts available to customers qualifying for the proposed EDR.

A. All provisions, charges, and adjustments in the participants' applicable standard offer retail rate schedule will continue to apply. The proposed EDR will apply discounts on electric bills specific only to the qualifying additional load of participating customers. Economic Development is defined as new or expanding business operations that build new facilities. The discounts for Economic Development will be 20% in Year 1, declining to 2.5% in Year 5, and terminating after Year 5. Economic Redevelopment is defined as new or expanding business operations that occupy existing vacant facilities. The discounts for business expansion that qualifies as Economic Redevelopment will be 30% in Year 1, declining to 5% in Year 5, and zero after Year 5.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

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

EXHIBIT
UNSE 29
admitted

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

Rebuttal Testimony of

Dallas J Dukes

on Behalf of

UNS Electric, Inc.

January 19, 2016

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Exhibit:

Exhibit DJD-R-1 - Proposed UNSE Customer Education Campaign for Three-Part Rates

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Dallas J. Dukes and my business address is 88 East Broadway, Tucson, Arizona, 85702.

Q. Did you file Direct Testimony in this proceeding?

A. Yes.

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

A. I am filing Rebuttal Testimony on behalf of UNS Electric, Inc. ("UNS Electric" or the "Company").

Q. How is your Rebuttal Testimony organized?

A. My testimony is organized as follows.

II. Rate Design.

III. Response to Staff's Testimony.

IV. Response to RUCO's Testimony.

V. Response to Other Intervenors.

VI. Net Metering Tariff..

VII. Economic Development Rate.

II. RATE DESIGN

Q. Please briefly summarize the Company's initial proposals regarding three-part rates.

A. The Company's Direct Testimony proposed (i) mandatory three-part rates for all partial requirement residential and small commercial customers who installed distributed generation after June 1, 2015 (collectively, "New DG Customers") and (ii) optional three-part rates for all other residential and small general service customers.

Q. What are the primary reasons for updating UNS Electric's rate design?

A. In this proceeding, the Company is attempting to gradually and fairly modify its rates to (i) reduce intra-class subsidization, (ii) promote fairness and recover costs from cost causers, (iii) provide flexibility to accommodate changing customer usage patterns, (iv) move toward rate structures that encourage the integration of new energy technologies on the electric system, thus promoting more efficient use of the electric system, and (iv) a sustainable rate structure that ensures that the Company can continue delivering safe, reliable and affordable electric services for the benefit of all our customers.

Q. To make it clear, are all of UNS Electric's proposed rate design changes simply to address partial requirement customers, such as solar DG customers?

A. No, and this is something that needs to be clarified. The Company has proposed several rate design changes in this docket. UNS Electric is attempting to address the totality of issues caused by recovering the vast majority of fixed cost with inverted block volumetric pricing, which is exacerbated by declining energy sales. (Please see the Rebuttal Testimony of UNS Electric witness H. Edwin Overcast for a detailed explanation of these issues.) In short, we are trying to gradually shift towards a rate design that more accurately reflects cost causation. Raising the monthly charge to a point where the

percentage of recovery of fixed costs increases is one proposal; eliminating the third tier for residential customers is another.

Some of the rate design changes do address the unique subsidization issues related to serving partial requirement customers with two-part rate design and net-metering, but some of which address other inequities. If two-part rate design is retained as an option for UNS Electric's customers, then raising the monthly basic service charge to $20 and eliminating a portion of the inverted rate structure are necessary changes that need to be made to begin addressing the subsidization of inefficient users of the system -low-usage and low load factor customers. That is part of the solution to address subsidization caused by vacant homes and seasonal customers, for example.

Both Staff and RUCO have recognized the need to update rate design and have made proposals that I address below. Other parties have suggested rate design concepts, such as minimum bills, that I believe are not as comprehensive a way to address the issues now or in the long term. Some parties such as Vote Solar and The Alliance for Solar Choice ("TASC") simply oppose all rate design changes without proposing any substantive alternatives, even those that are not targeted to deal with the issues DG specifically causes.

III. RESPONSE TO STAFF'S TESTIMONY.

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

A. Yes, I have.

Q. Does the Company support Staff's rate design recommendation to transition all of UNS Electric's residential and small general service ("SGS") customers to a new tariff that includes a demand charge (three-part rates)?

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

Q. Why didn't the Company propose transitioning all residential and SGS customers to three-part rates in this proceeding?

A. The Company proposed volumetric rates in our initial filing and optional three-part rates that include an increased basic service charges and the elimination of an artificially inflated higher third tier in the volumetric rate design. The proposed changes were designed to (i) mitigate intra-class subsidization, (ii) begin the transition to multi-part rate structures and (iii) move towards more fairly charging customers. My direct testimony was based on the assumption that the approved rate increase and rate design changes would be in effect in mid-2016, as initially requested by the Company. Based on our original plans to complete the installation of our automated meter reading system (in 2017) and implement a customer education and information program, implementing three-part rate design for all customers by mid-2016 seemed somewhat aggressive when we filed our application in May 2015.

Q. How has Staff's proposed rate design addressed transitioning customers to multi-part rates?

A. Staff's proposed long-term rate design plan eliminates the need for multiple rate case proceedings to implement initial three-part rates for all our customers by: including the proposal of transitional volumetric rates, a transition and education period, "first-step" three-part rates (i.e. only collecting a small portion of demand-related costs in this case with a goal of gradually updating the demand rate over the next couple of rate cases); and

leaving rate design open for an extended period of time to allow for any significant unintended bill impact and revenue consequences to be addressed. Staff's proposal, in conjunction with accelerating the deployment of our automated meter reading system and the transition plan included as part of my Rebuttal Testimony, enables three-part rate design to be approved for all customers in this proceeding.

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

A. Staff provides several compelling reasons for its recommendation regarding three-part rates. Mr. Broderick correctly states, among other things, that three-part rates (i) better inform customers considering new technologies, including DG, about the bill impacts of their technology choices, (ii) make significant progress towards all the issues arising from the proliferation of DG, and (iii) reflect cost causation better than rates that rely on energy charges only to recover fixed costs.

Q. Do you agree with Staff's rationale?

A. Yes, I do.

A recent newspaper article in the Kingman Daily Miner (1/8/16) included the following quotes from UNS Electric customers:

> John and Sandi Myers spent about $21,000 to install a new solar unit in their Kingman home in November.
>
> They're hoping to bring their monthly electric bill down to nothing, the way it was at their solar-powered home in Lake Havasu City.

> "We're both retired on a fixed income, so we're looking at not having an electric bill," Sandi said. "We had older panels in Lake Havasu, so they were not as efficient. For nine months, we didn't have a bill. We really liked it. We didn't have to worry about cranking the air conditioning."
>
> Myers said they won't be getting the rebates they had in Lake Havasu. But with the 30 percent tax credit, they won't have to pay any federal taxes for 2015.

This excerpt illustrates a few of the significant issues we're trying to address with the gradual changes proposed by not only the Company, but also by Staff and RUCO such as: 1). It reflects the availability of advancing technologies at reduced costs available to our customers. "We had older panels in Lake Havasu, so they were not as efficient"; 2). That federal tax credits provide significant economic incentives to our customers to invest in these new technologies. "But with the 30 percent tax credit, they won't have to pay any federal taxes for 2015"; 3), that present rate design promotes economic decisions based on false price signals, "we're looking at not having an electric bill;" and 4) that current rate design and rules promote the inefficient use of the system, "We didn't have to worry about cranking the air conditioning".

If customers aren't charged for the costs that they require the Company to incur to provide them with the electricity they need, whenever they need it, customers will never have an incentive to use the system more efficiently. Properly designed three-part rates provide many benefits, ranging from charging customers more equitably for electric service to encouraging more efficient use of the system, to the integration of new technologies.

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

A. No, However, our meter replacement program is on track to have demand reading capability in place for all customers by the by the end of 2016.

Q. Does the Company agree with Staff's proposed residential basic service charge?

A. Staff's proposal to move the residential basic service charge to $15 per month is representative of the customer's direct cost and minimum system cost. However, it is important to note that a $15 basic service charge is still far below the average fixed cost to provide service to a residential customer. The Company supports Staff's proposed basic service charge if the Commission adopts an acceptable three-part rate structure for all residential and SGS customers. However, the Company cannot support this lower customer charge if traditional, two-part volumetric rates are proposed for the Commission's consideration.

Q. Does the Company agree with Staff's proposed Demand Charge?

A. We are materially in agreement with Staff's proposed demand charge with a few minor modifications that are described in greater detail in the Rebuttal Testimonies of Craig A. Jones and H. Edwin Overcast. The primary changes we propose to Staff's proposal are twofold:

1.) The addition of a 15% minimum load factor for purposes of calculating the demand charge.

This temporary measure will address concerns some parties have regarding an atypical customer's usage causing demand charge spikes. Essentially, the billed demand (peak hour usage, during on-peak hours), will be adjusted so as to not be less than the average hourly load of the customer divided by 15%, thereby

temporarily protecting certain customers from a higher bill resulting from an inefficient usage of the system until three-part rates are further adjusted in the Company's next rate case.

For example, if a customer used 800 kWh in a 30 day billing period, their average hourly load would be 1.11 kWh or kW [800 kWh / (24hrs x 30 days)]. If their highest hourly usage was 10 kWh or 10kW they would have a measured load factor of 11.1% (1.11 kW avg. load / 10 kW peak load). Without the load factor minimum, this customer would see a demand charge of $50 assuming a $5 per kW rate ($5 per kW x 10 kW peak load). With the minimum load factor the billed demand would be adjusted to 7.4 kW [1.11 kW avg. load / 15% minimum load factor]. Which would lead to an adjusted demand charge of $37 [$5 per kW x 7.4 kW adjusted peak load].

This is described in greater detail in the Rebuttal Testimony of Craig Jones, but is being proposed as an additional safeguard for our customers. Along with Staff's proposal of limiting the amount of demand cost recovered through these "first-step" demand rates, the use of one hour intervals for billed demand measurement and measuring billed demand during on-peak periods only – the load factor minimum will limit the possibilities for adverse and unexpected bill changes as a result of moving customers to three-part rate structures.

2.) Another change the Company is proposing to Staff's three-part rate proposal is to recover generation costs through the demand charge. This will be discussed in more detail in the Rebuttal Testimonies of Craig Jones and H. Edwin Overcast. Staff's proposal to base demand charges on the on-peak usage is directly associated with the cost of generation.

Q. Has the Company anticipated the need for a comprehensive communication and education plan for its customers as three-part rates become available for residential and small general service customers?

A. Absolutely. It has been the Company's objective all along to start communicating about its proposed three-part rate design at the conclusion of the proceeding. Contrary to TASC's erroneous assertion that the Company would not educate customers about three-part rates[1], we will implement a comprehensive communication and outreach plan to educate customers about all important rate and rate design changes that are approved by the Commission at the conclusion of this proceeding. I also strongly disagree with various Intervenors who have suggested that our customers simply will not be able to understand three-part rates, particularly given our plans for extensive outreach and education,

Q. Please describe the Company's education/outreach plans to inform customers about three-part rates.

A. The Company plans to promote awareness about three-part rates through a comprehensive communications campaign. A description of the Company's proposed education campaign is attached as **Exhibit DJD-R-1**. The key elements of the plan are described below.

- **Timing.** The campaign would provide customers with access to information about their individual electric demand at least three months prior to implementing such three-part rates.
- **Messages.** The primary customer messages will focus on the definition of a demand charge, how it is calculated, potential bill impacts and energy efficiency tips aimed at reducing customer demand.

[1] Direct Testimony of Mark Fulmer (Rate Design and Cost of Service) ("Fulmer"), Page 23, lines 1-7.

- **Communication Channels.** The Company intends to use a variety of communication methods, including focus groups, customer bill messages, UNS Electric's website, social media, the customer electronic newsletter and brochures.
- **New Bill Format.** UNS Electric is in the process of redesigning customer bills. The Company expects to introduce the new bill design to customers at the same time that three-part rates are implemented.

Q. Please discuss Staff's proposed framework for transitioning customers to three-part rates.

A. Staff proposed some general guidelines for a rate migration plan. Staff states the following in its testimony:

- **Usage data.** Rate design should not change until customers can review at least three months of comprehensive usage data. Such usage data should be provided to customers on an ongoing basis.[2]
- **Phase-in.** The transition could start as early as January 1, 2017. The transition should be completed in phases and higher use customers should be transferred first.[3] The transition time for each phase should be at least four months.[4]
- **Unintended consequences.** The rate design portion of the case should remain open for at least 18 months to monitor the transition and deal with problems as they occur.[5]
- **Vulnerable customers.** Potentially vulnerable customers should self-identify; however, existing DG customers do not comprise a vulnerable group.[6]

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[2] Direct Rate Design Testimony of Howard Solganick ("Solganick"), page 13 lines 17-20, page 30 lines 17-26.
[3] Solganick, page 13 lines 22-26, page 14 lines 103.
[4] Solganick, page 32 lines 1-4.
[5] Solganick, page 14 lines 5-10.
[6] Direct Rate Design Testimony of Thomas Broderick ("Broderick"), page 9, lines 14-23, page 10 lines 1-8.

Q. Does the Company's proposed transition plan comport with the rate transition guidelines proposed by Staff?

A. Yes, we generally agree with the guidelines set forth by Staff as summarized above. Our primary difference is with regards to the timing of when customers are transitioned to new rates.

Q. Does the Company have any recommendations regarding the phase-in of three-part rates?

A. Yes. After much consideration, the Company believes that migrating all residential and SGS customers at one time, in February or March of 2017, is preferable to migrating certain customers at different points in time. We would use transitional two-part rates for all residential and SGS customers, including all DG customers, reflecting our new revenue requirement that would be in effect from the decision in this rate case until the migration date.

Q. Why does the Company believe that migrating all customers at once is better than in stages?

A. We think there are a few compelling reasons to migrate all customers at the same time. First and foremost, we think that our customer education and communication plans will be more effective if it is directed at our entire customer base rather than trying to deliver information to different customer groups at different times.

Another consideration is the seasonality of UNS Electric's bills. Implementing three-part rates during a reduced load (shoulder) month, when most bills are lowest for customers, will mitigate initial confusion between bill impacts attributable to the addition of the demand charge, versus a seasonally driven increase. This combined with the minimum load factor and other compromises designed to mitigate initial impacts, should lead to

very moderate bill impacts. Please see the Rebuttal Testimony of Craig A. Jones for a more detailed discussion of bill impacts associated with transitioning to the Company's proposed three-part rate structures.

Our customer service performance should also benefit from a one-time implementation rather than a phased in approach. Having all of our customers under a similar rate structure will make it easier for our Customer Service Representatives ("CSRs") to effectively and accurately respond to customer inquiries. We plan to conduct internal training and develop educational materials for our CSRs in order to prepare them for the likely increase in call volume following the implementation of three-part rates.

Q. What can the Company do ahead of time to help mitigate unintended bill impacts resulting from the implementation of three-part rates?

A. The Company is already analyzing data and comparing bill impacts of implementing three-part rates versus current volumetric two-part rates. Once new rates are approved, and prior to implementing the new rate design, we expect to work closely with Staff and RUCO and share bill comparison data to identify and address bill impacts that were not anticipated as part of the approved rate design changes *prior* to implementing the three-part rates. Proactively addressing potential billing issues before even introducing those rates to any of our customers will help ensure a smoother transition and mitigate unintended consequences.

Q. Can you provide an example of when the Company could begin implementing its customer education plan?

A. Yes. For illustrative purposes, the following high-level timeline assumes that the Commission issues a decision in this proceeding in June 2016.

- May - June 2016. The Company implements transitional volumetric rates based on the approved revenue requirement in this case.
- Present – December 2016. UNS Electric will collect and analyze billing data to determine if any rate design changes are necessary prior to billing customers under three-part rates. Essentially comparing customers that we have demand data for under both bill designs throughout this time frame.
- May – October 2016. UNS Electric will begin to roll out its customer education plan.
- Beginning no later than November 2016. UNS Electric provides usage and demand data to customers.
- First Quarter 2017. All residential and SGS customers are migrated to three-part rates. UNS Electric also introduces a redesigned bill.

I would like to emphasize that this high level timeline is preliminary and for discussion purposes only.

Q. Does the Company support Staff's position that existing Net Metering customers should be moved to three-part rates?

A. Yes. But, the Company is also supportive of a properly designed volumetric rate being retained for the period of time initially proposed by the Company (expiring May 31, 2035) for the present customers being billed using Net Metering Rider-4, as defined in my Direct Testimony. In my Direct Testimony, I proposed that Net Metering Rider-4 be retained for all service points being billed with the application of Rider-4 (net metered customers) as of June 1, 2015 and all completed, approved and connected service points – where the Company received applications prior to June 1, 2015.

Q. Does the Company support Staff's position that existing net metering riders should <u>not</u> be modified in this proceeding?

A. No. As discussed in the Rebuttal Testimonies of Carmine Tilghman, Craig A. Jones and H. Edwin Overcast, the Company continues to propose the replacement of the existing Net Metering Rider-4 with the revised Net Metering Rider-10, which eliminates the banking of excess generation (rolling over kWh unused to proceeding billing periods) and credits the customer for excess generation at the applicable Renewable Credit Rate.

All customers, including those who meet the requirements for Net Metering Rider-10 as proposed by the Company, would be on the applicable three-part rate approved for their rate class and would not be eligible for any grandfathered two-part rate designs.

IV. <u>RESPONSE TO RUCO'S TESTIMONY.</u>

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

A. Yes.

Q. Please provide your general thoughts on RUCO's rate design proposals.

A. As discussed by RUCO witness Lon Huber in his direct testimony, his rate design proposals were developed based on four core guidelines. One of those guidelines was to establish rates that both provide more accurate price signals to DG customers and <u>minimize the cost shift</u>. We agree that is an important guideline. We also appreciate RUCO's willingness to offer alternatives to the Company's proposed three-part rate design and net metering rider with regards to partial requirement customers. Unfortunately, we find their various rate proposals to be inadequate (and in some instances confusing) in beginning to address the overall issues surrounding today's antiquated rate design. The proposal offered by the Company in its direct filing and

Staff's proposal as modified in our rebuttal position are superior at beginning to address the foundational problems surrounding the present two-part rate design and the needed modernization of rates.

Q. Please address RUCO's proposed changes for DG customers.

A. RUCO proposes the Company provide new DG customers the option of selecting one of three new rates. RUCO's proposed optional "DG TOU Rate" shares some similarities with the Company and Staff's proposed three-part rate design.

> The three components of this rate are 1) A minimum bill 2) A Variable per kWh energy Charge and 3) a variable per kW Demand Charge covering over peak hours during summer months.[7]

One key difference is that RUCO's proposed demand charge would only apply during summer peak periods.[8] UNS Electric does not support applying demand charges only on a seasonal basis. Moreover, the Company does not support *optional* three-part rates for new DG customers; when coupled with retaining the present two-part rate structure as an option for all other Customers.

Q. Does RUCO support the Company's proposals to increase the monthly basic service charge and eliminate the third tier of its inclining block rate structure?

A. No. RUCO recommends a residential monthly basic service charge of $12.26[9], which is far below the Company's proposed $20 basic service charge. RUCO's proposed monthly basic service charge would collect less than 23% of the Company's average fixed cost to

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[7] Direct Testimony of Lon Huber ("Huber"), page 14 lines 3-5.
[8] Huber, page 15 lines 18-20.
[9] Huber Exhibit 2 page 1.

serve a residential customer. RUCO also opposes the elimination of the third tier of the Company's inclining block rate structure.[10]

Q. Do you agree with RUCO's position regarding basic service charges?

A. No. As I stated in the Company's direct filing, electricity use per residential customer fell by nearly 4% between 2012 and 2014[11]. Waiting for growth in electricity consumption to return to historic levels is simply not an option. We cannot continue to rely on volumetric energy sales to recover the vast majority of our fixed costs and earn an appropriate rate of return in an environment of flat to declining energy usage. Such a small increase is simply inadequate to make meaningful progress towards recovery of fixed costs.

Q. Do you agree with RUCO's position that the third rate tier should remain in the Company's inclining block pricing structure?

A. Absolutely not. As discussed in the Direct and Rebuttal Testimonies of Craig A. Jones and the Rebuttal Testimony of H. Edwin Overcast - there is simply no cost justification for these inverted block tiers which results in an inequitable proportion of cost recovery from higher usage and load factor customers. Accordingly, we are unduly penalizing customers with above average usage or that use the system more efficiently.

This is exasperated by the growing level of low or no usage bills we are seeing on the system. One can simply look at our customer billing data. During the calendar year 2014 (the test year used in this case), the Company issued over 23,000 zero usage bills.[12] This represents a 144% increase over "zero bills" issued during the previous test year (12

[10] Huber, page 7 lines 19-22.
[11] Direct Testimony of David G. Hutchens, page 5 lines 16-20.
[12] Schedule H-5, page 1 (filed May 4, 2015 with the Company's rate application).

months ended June 30, 2012). It is important to note that these billing statistics do not include our low income customers.

V. RESPONSE TO OTHER INTERVENORS.

Q. How would you respond to TASC and Vote Solar accusing UNS Electric of unfairly discriminating against DG customers by proposing a three-part rate with demand charges?

A. That, quite frankly, is wholly unfounded. There is more than ample justification to put DG customers on a separate rate structure, as the Nevada Public Utilities Commission recently ordered. Further, UNS Electric witness H. Edwin Overcast, , provides detailed Rebuttal Testimony as to why separate rate treatment is appropriate for DG customers, why the current rate structure is not capable of reflecting costs for DG customers (as partial requirements customers) and why a separate rate class for DG customers must include demand charges. In short, and especially given the fact that allocating costs on a two-part rate design for DG customers does not provide the right price signals or properly reflect cost recovery or causation, DG customers should be placed on a separate three-part rate with demand charges. Thus UNS Electric strongly disagrees with any assertion that it is discriminatory to recover the cost of serving a partial requirements customer (DG customer) based on how they use the system - and not doing so based on how a full requirements customer uses the system.

Q. Have other public utility commissions found justification to place DG customers in a separate rate class?

A. Yes. I believe I've detailed the Nevada PUC's decision justifying the placement of DG customers (NEM customers) in a separate rate class. The Utah Public Service Commission, in Docket No. 14-035-114, found reason to order, on November 10, 2015,

cost of service studies that segregates DG customers from the class they would otherwise participate in and as part of the Utah PSC's examination of the costs and benefits of net metering. Clearly, utility commissions in other states are finding that DG customers impact the grid differently than traditional full requirements customers.

Q. TASC witness Marc Fulmer alleges, on page 13 of his Direct Testimony on Rate Design, that DG customers' bills would more than double under UNS Electric's proposal versus allowing net metering with banking. How do you respond?

A. First, even if this were the case, the question could easily be turned to ask why non-DG customers should continue to subsidize DG customers to the level that DG customers are allowed to cut their bills by 60% or more.

Q. TASC witness Marc Fulmer notes five main concerns regarding UNS Electric's proposed Rider 11 and the RCR. How do you respond to his concerns?

A. We have already addressed these concerns in our Direct and Rebuttal Testimonies but let me address these concerns succinctly here:

1. Rates are not set based on a benefit-cost analysis. The Commission establishes rates based on cost causation and cost-of-service principles using a historical test year with pro forma adjustments. Resource planning typically uses a cost-benefit approach which then serves as a guideline for the Company's long-term resource decisions.
2. We have already discussed how use of the TEP transaction for a small utility-scale project tied to its distribution system is an acceptable proxy to set the RCR. Mr. Fulmer constantly refers to the benefits of DG over utility-scale solar in justifying his argument. Keep in mind that he provides no empirical evidence to support his position, and testifies on behalf of an entity that was supported by

some of the largest DG leasing entities in the nation (all of which are not based in Arizona).

3. It was never the intent of UNS Electric to have an automatic free-flowing variable RCR. We assumed there would always be Staff review and/or Commission approval of any proposed change to the RCR. This argument is a red herring. I believe TASC's main goal is to keep the subsidy as high as possible to benefit its members' business and financial interests, as opposed to what is best for all of UNS Electric's customers.

4. We agree the value of renewable power may not be the same across all resources. We have not tried to use geothermal or wind as a proxy for the RCR for excess energy from DG systems (which are mainly solar PV).

5. It is not the job of the Commission or UNS Electric to preserve the value of federal solar tax credits for TASC members. Keep in mind that in most solar leasing service arrangements, the TASC members obtain the tax benefits (they do not remain with the DG customer). The goal in this case is to establish just and reasonable rates for all of our customers.

Q. Do you have any specific comments relative to the rate design testimony provided by the Arizona Utility Ratepayer Alliance ("AURA")?

A. AURA's direct testimony opposing demand charges and changes to UNS Electric's net metering tariff largely mirrors the arguments Vote Solar and TASC have set forth. I will not repeat myself here in responding to those same arguments. I will, however, reemphasize that UNS Electric is trying to address *all* ratepayer subsidization in this case, by moving rates closer to cost-of-service. In doing so, we understand that some subsidies will always remain and are deemed to be in the overall public interest - like with those provided to low-income customers. Even under UNS Electric's direct case, DG customers would still retain significant subsidies; although the magnitude of those

subsidies would be less. So to the extent AURA suggests that UNS Electric's proposals would end subsidization of DG, that claim is simply false.

VI. NET METERING TARIFF.

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

A. Under UNS Electric's proposed Net Metering Tariff, New DG Customers, among other things, (i) would not be allowed to "bank" or carry-forward excess kilowatt-hours ("kWh") to offset future electricity consumption and (ii) would be compensated for excess energy at the Renewable Credit Rate.[13]

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

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

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

A. Yes, without question. I would like to point out that UNS Electric and its sister company, TEP, filed applications in March 2015 to update their net metering tariffs.[14] Although both UNS Electric and TEP believe that the Commission can approve a net metering tariff outside of a rate case, several parties who are Intervenors in this rate case, including TASC[15], Vote Solar[16], the Arizona Solar Deployment Alliance[17] and the Arizona Solar

[13] Equivalent to the most recent utility-scale renewable purchased power agreement connected to the distribution system of Tucson Electric Power.

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

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

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

Energy Industry[18], argued that a net metering tariff must be approved in a rate case. In light of the procedural posture in that docket, in June 2015, TEP withdrew its net metering application and accelerated the filing of its rate case.[19] Yet these parties have yet to offer any new net metering proposals in this docket.

While we understand Staff's desire to wait for the outcome of the Commission's investigation of the value and cost of DG (Docket No. E-00000J-14-0023)[20], this proceeding is the proper venue for approval of a new net metering tariff for UNS Electric. It is unclear when that proceeding will conclude and what result it will ultimately produce. On the other hand, this rate proceeding will provide sufficient Company specific data and evidence to support the Commission's approval, modification or rejection of UNS Electric's proposed net metering tariff.

Q. Do you have any estimates of how the Company's proposed three-part rate structure and net metering tariff will impact new DG customers?

Yes. The table below demonstrates that new DG customers will continue to see significant savings under the Company's proposed three-part rate structure and net metering tariff. The table shows average pre-tax monthly bills for residential full-requirements and DG customers using an average of 500 kWh, 900 kWh, 1,200 kWh, and 1,500 kWh per month.

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

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

[19] (Notice of Withdrawal of Application filed June 19, 2015, Docket No. E-01933A-15-0100)

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

Monthly Usage	Transitional 2-part Rate: No DG	Proposed 3-part Rate: No DG	Proposed 3-part Rate: DG with Current Net Metering	Proposed 3-part Rate: DG with Proposed Credit for Export
500 kWh per Month				
Average Monthly Bill (pre-tax)	$ 59.73	$ 63.23	$ 27.84	$ 31.03
Bill Savings from 2-part Rate	NA	$ (3.51)	$ 31.89	$ 28.69
Bill Savings from 3-part Rate	NA	NA	$ 35.40	$ 32.20
900 kWh per Month				
Average Monthly Bill (pre-tax)	$ 100.14	$ 100.08	$ 36.01	$ 41.77
Bill Savings from 2-part Rate	NA	$ 0.06	$ 64.13	$ 58.38
Bill Savings from 3-part Rate	NA	NA	$ 64.07	$ 58.31
1,200 kWh per Month				
Average Monthly Bill (pre-tax)	$ 132.20	$ 122.51	$ 42.05	$ 46.10
Bill Savings from 2-part Rate	NA	$ 9.69	$ 90.15	$ 86.10
Bill Savings from 3-part Rate	NA	NA	$ 80.46	$ 76.40
1,500 kWh per Month				
Average Monthly Bill (pre-tax)	$ 166.00	$ 147.20	$ 47.03	$ 52.23
Bill Savings from 2-part Rate	NA	$ 18.81	$ 118.98	$ 113.77
Bill Savings from 3-part Rate	NA	NA	$ 100.17	$ 94.97

It is evident from the comparisons presented in this table that DG customers on the Company's proposed three-part rate structure and net metering tariff will continue to see significant savings when compared to bills under full requirements utility service. For example, a DG customer under the Company's proposed three-part rate and net metering tariff using an average of 900 kWh per month will save $58.38 monthly compared to the Company's proposed transitional full requirements two-part rate and $58.31 compared to the Company's proposed full requirements three-part rate. This represents monthly bill savings of approximately 58% from full requirements service in both cases. The same residential DG customer on the Company's proposed three-part rate and current net metering tariff would save an average of $64.13 and $64.07 per month from the full requirements transitional two-part rate and proposed three-part rate, respectively.

Q. How do the Company's residential three-part rate design and net metering tariff proposals impact fixed cost recovery from DG customers?

A. Not only will new DG customers continue to realize significant monthly savings under the Company's proposal, they will also contribute more toward the fixed costs of serving them. The table below presents fixed cost recovery for the same customer usage levels as the previous table. As this table shows, a new DG customer using an average of 900 kWh per month on a combination of the Company's proposed three-part rate and net metering tariff will contribute all but $6.76 per month to the fixed costs of service. This represents an increase of $28.37 over an equivalent customer on a two-part rate and the current net metering tariff. As I mentioned earlier, this customer will still be saving $58.38 a month on their electric bill while contributing much more to fixed cost recovery.

Even if this same DG customer using 900 kWh per month takes service under the Company's proposed three-part rate and the current net metering tariff, the contribution to fixed costs increases from $15.43 per month to $35.75 per month compared to service under the transitional two-part rate. The contribution to fixed cost recovery increases by $20.32, while the DG customer realizes savings of $64.13 per month on the monthly electric bill.

Monthly Usage	Transitional 2-part Rate: No DG	Transitional 2-part Rate: DG with Current Net Metering	Proposed 3-part Rate: DG with Current Net Metering	Proposed 3-part Rate: DG with Proposed Credit for Export
500 kWh per Month				
Monthly Fixed Cost Recovery	$ 32.18	$ 15.32	$ 27.64	$ 32.30
Average Monthly Bill (pre-tax)	$ 59.73	$ 15.58	$ 27.84	$ 31.03
Unrecovered Fixed Costs	NA	$ 16.86	$ 4.54	$ (0.12)
Monthly Bill Savings	NA	$ 44.15	$ 31.89	$ 28.69
900 kWh per Month				
Monthly Fixed Cost Recovery	$ 50.56	$ 15.43	$ 35.75	$ 43.80
Average Monthly Bill (pre-tax)	$ 100.14	$ 15.77	$ 36.01	$ 41.77
Unrecovered Fixed Costs	NA	$ 35.13	$ 14.81	$ 6.76
Monthly Bill Savings	NA	$ 84.37	$ 64.13	$ 58.38
1,200 kWh per Month				
Monthly Fixed Cost Recovery	$ 66.10	$ 15.63	$ 41.67	$ 52.13
Average Monthly Bill (pre-tax)	$ 132.20	$ 16.12	$ 42.05	$ 46.10
Unrecovered Fixed Costs	NA	$ 50.47	$ 24.43	$ 13.97
Monthly Bill Savings	NA	$ 116.08	$ 90.15	$ 86.10
1,500 kWh per Month				
Monthly Fixed Cost Recovery	$ 83.37	$ 15.84	$ 46.52	$ 59.60
Average Monthly Bill (pre-tax)	$ 166.00	$ 16.49	$ 47.03	$ 52.23
Unrecovered Fixed Costs	NA	$ 67.53	$ 36.86	$ 23.78
Monthly Bill Savings	NA	$ 149.51	$ 118.98	$ 113.77

VII. ECONOMIC DEVELOPMENT RATE.

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

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

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

A. Yes. The testimonies of Staff[21], RUCO[22], NUCOR[23], Walmart[24] and AIC[25] generally recognize the merits of UNS Electric's EDR; however, some of these parties express concerns about costs being shifted from EDR customers to other customer classes. I would like to emphasize that the any lost non-fuel revenues resulting from discounts provided to customers through the EDR *will be borne by the Company*. UNS Electric will not seek recovery of any lost non-fuel revenues associated with the EDR in future rate case proceedings. The long-term benefits of attracting or retaining large, high load factor customers greatly outweigh the short-term costs.

Q. Other than concerns about cost shifting, were there any other noteworthy issues addressed by the parties?

A. Yes. NUCOR, AURA, and RUCO recommended changes to or expressed additional concerns with the proposed EDR.

Q. Please address NUCOR's proposals with respect to the Company's proposed EDR.

A. NUCOR generally supports the Company's proposed EDR, but believes that the load factor requirement needs clarification. NUCOR recommends the following language:

> The monthly load factor shall be calculated based upon the *customer's billing demand* and monthly energy usage.[26] [Emphasis added]

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[21] Solganick page 52 lines 5-7
[22] Huber page 8, lines 20-23, page 9 lines 1-6.
[23] Direct Testimony of Dr. Jay Zarnikau ("Zarnikau"), page 30, lines 15-18.
[24] Direct Testimony of Gregory W. Tillman ("Tillman"), page 9 lines 8-19.
[25] Direct Testimony of Gary Yaquinto ("Yaquinto"), pages 8-9, lines 1-22.
[26] Zarnikau, page 31, lines 5-6.

Q. Do you agree with NUCOR's recommendation?

A. No. It is the Company's intent to calculate the load factor requirement for the proposed EDR based on projected measured demand. NUCOR's recommendation to change the load factor requirement in the proposed EDR stems from its position (which the Company opposes) that a LPS customer's billing demand should be calculated as the customer's average demand at the time of the 4 system coincident peaks during the preceding year.[27] This approach would generally reduce this customer's billing demand and increase the resulting load factor calculation making it more likely for this customer to meet the threshold.

The Company's proposed EDR is targeted at new or additional load not currently on the UNS Electric system and there is no billing demand on which to base a load factor calculation. For additional loads associated with new customers on the system and relocations to the UNS Electric service area, basing the monthly load factor calculation on a customer's billing demand would actually increase ambiguity in direct opposition to NUCOR's intent.

Also, if NUCOR's recommendation were adopted, existing customers in rate classes other than NUCOR's whose billing demand is calculated as the Company proposes, along with a demand ratchet, would be less likely to meet the threshold for participation. This is because the demand ratchet generally increases billing demand over actual demand and thereby reduces the calculated load factor. The load factor criteria for the EDR should be based on actual expected demand and not be made contingent on the calculation of billing demand for different rate classes.

[27] Zarnikau, page 31, lines 7-10.

Q. Please summarize RUCO's proposals with respect to the Company's proposed EDR.

A. RUCO believes that the proposed EDR has some merit but safeguards must be built in to protect non-participating ratepayers. RUCO proposes that (1) total program cost be capped at $3 million, (2) customers receiving EDR discounts participate in DSM programs to lower peak demand needs, and (3) a study be conducted into the systemwide and local economic benefits within three years from approval.[28]

Q. Please address RUCO's proposals.

A. First, because the cost shifting issues were addressed earlier neither a program cost cap nor a study of benefits is necessary. UNS Electric will not seek recovery of any lost non-fuel revenues or under-recovered costs associated with the EDR in future rate case proceedings. Second, requiring EDR participants to also participate in DSM programs is also unnecessary. UNS Electric markets DSM programs to all of its customers and sees no need to single out EDR participants for mandatory participation. Also, the 75% minimum load factor requirement for participation in the program assures that the EDR loads added to the system are the type that will encourage increased energy sales without undue pressure on peak demand needs.

Q. What are the concerns expressed by AURA with respect to the Company's proposed EDR?

A. In addition to the cost shifting concerns addressed above, AURA cites issues with the APS AG-1 program in opposition to the proposed EDR. Specifically, AURA cites the following APS AG-1 program issues:[29]

- Any program with a lottery/cap will leave some qualified customers out of the program.

[28] Huber, page 8, lines 22-23; page 9, lines 1-6.
[29] Direct Testimony of Patrick J. Quinn, page 5, lines 1-11.

- APS has absorbed lost revenues from the original AG-1 pilot but wants full recovery for the next phase.

Q. Do you find merit in any of AURA's concerns?

A. No. AURA's criticism that a decrease in revenues from one class necessarily shifts costs to other classes is unfounded in relation to the Company's proposed EDR. The EDR will apply only to incremental load on the system, not existing load. The Company has not proposed that it will seek recovery of any non-fuel revenues between those collected and those which would have been collected at full rates, but for the EDR, in a future rate case. In fact, in a future rate case test-year revenues will be calculated based on adjusted test-year billing determinants and full retail rates. There would be no revenue shortfall attributable to EDR customers as a result, only increased sales.

As for AURA's comparisons of the proposed EDR with the APS AG-1 program, Mr. Quinn's criticisms are more apt regarding the Company's proposed buy-through rider, Experimental Rider 14, than the proposed EDR. Both the APS AG-1 program and proposed Rider 14 use a lottery process to select participants. The EDR has no such lottery process. EDR applicants will approach UNS Electric if they have plans to initiate or expand business in the Company's service area. The Company will perform due diligence to determine whether the applicants' expected additional loads and increased business activity meet the EDR criteria. If a prospective EDR participant meets the program criteria and is allowed to participate in the EDR program, the additional electric sales will allow the Company to spread its fixed costs over more output making it possible that costs to other customers on the system are reduced. This is a much different impact than the APS AG-1 and proposed Rider 14 type programs where existing customer loads bypass utility generation service and leave the Company and other customers on the system to pick up the unrecovered fixed costs.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

Exhibit DJD-R-1

UniSourceEnergy SERVICES

Proposed Customer Education Campaign for "Three-Part" Electric Rates

Summary

UNS Electric, Inc., which provides electric service under the UniSource Energy Services (UES) brand, has not previously used residential rates that include a "demand charge." If the three-part rate plan proposed in the company's most recent application for new rates is approved, the Company plans to promote awareness of its key elements through a comprehensive communications campaign.

The campaign would provide customers with access to information about their individual electric demand and would continue for at least three months before the new rate design is implemented. The campaign also would promote awareness of energy efficiency tips and programs the Company plans to develop to help customers manage their electric demand.

Our campaign would feature the following key messages and components.

Key Messages

- Explanation of the new rates, including how the demand charge is calculated and the potential bill impact based on customers' individual household electric demand.
- The new rates cover the cost of system upgrades UES has made to provide safe, reliable service.
- Customers can reduce their bills through energy efficiency efforts that reduce electric demand.
- Assistance is available for qualifying low-income customers.
- Explanation of the effective date of the three-part rates and the transition plan

Components

Revised Name – We plan to develop a new, more customer-friendly name for the "demand charge" that would be included in an approved three-part rate plan for residential customers. Although the concept of electric demand is well understood in our industry, we are concerned that residential customers may associate the word with its more common definition and conclude their utility is simply "demanding" more money from them. We will use a customer focus group (see below) to evaluate prospective alternatives and select a name that promotes better understanding. Also, we do not plan to refer to our approved residential tariffs as "three-part rates," as that description is intended for use in regulatory dockets.

Customer Focus Groups – We would conduct a focus group with UNSE residential customers to discuss the prospective rate change and evaluate alternate ways to explain three part rates with a demand component. We expect this meeting would help us select a more customer-friendly name for the "demand charge," refine messages for the

communications described below and improve the effectiveness of our outreach.

Customer Bills – We plan to add messages to customer bills alerting them to the impending change and inviting them to visit our website (uesaz.com) or call our customer care center for more details. We also plan to provide customers with a reading of their electric demand from the current billing period, calculated as it would be under the approved three-part rate.

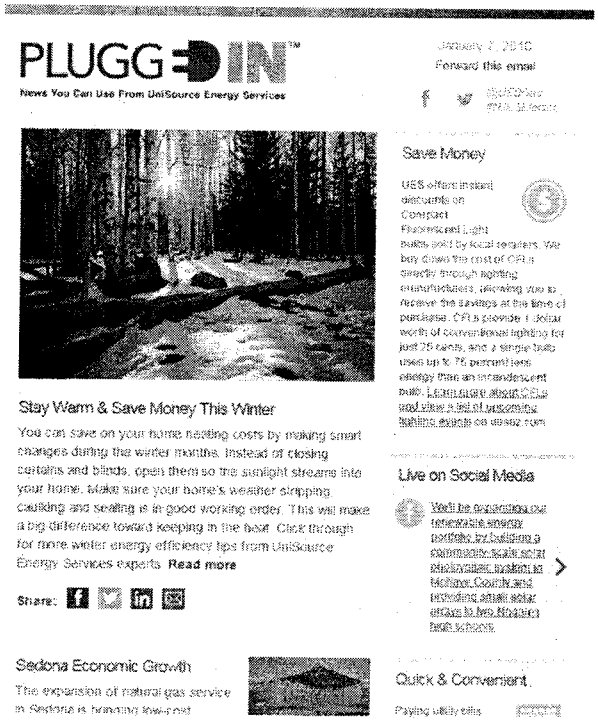
Website Content – We would post an extensive explanation of our approved rates on our website, including details about its rollout, answers to anticipated questions and a link to the approved tariff. Additionally, customers who establish online access to their UNS Electric bill could review the electric demand details presented on their bills, as described above. We would provide information about the assistance available for qualifying low-income customers. Finally, we will prepare and post energy efficiency tips designed to help residential customers manage their electric demand to save energy and save money with three-part rates.

Bill Inserts – We would prepare and distribute two bill inserts to alert residential customers to an impending switch to three-part rates. The first bill insert, delivered in the period before the new rate takes effect, would alert customers to the new rate and direct them to review their bill and visit our website for more information. The second bill insert, distributed with the first bill that includes the new rate, would include graphics and instructions intended to help customers identify and understand the new terms and charges on their bill. Both inserts will invite customers to visit uesaz.com or call our customer care center for more information.

Brochure – Information presented on the bill insert and website will be incorporated into a brochure that will be made available upon customer request and at various locations as needed.

Customer Call Center – Our Customer Care team will be trained extensively to answer customer questions about the new three-part rates, including the "demand charge," based on the material prepared for distribution on our website. Customer Service Representatives will review lists of frequently asked questions and keep such material on hand to ensure accurate, consistent responses. Our representatives may mail brochures to customers or refer them to our website to provide additional information.

Plugged In – We plan to promote awareness of the rate in a "special edition" of Plugged In, our quarterly email newsletter for customers. The special edition will include some of the explanatory content posted on our website, presented in an engaging, easy-to-read format. Plugged In also will provide direct links to our website for additional information. This edition of the newsletter will be distributed in the months before the new rate would take effect. The electronic newsletter is distributed to more than 18,000 UNS Electric residential customers.



News Media – We will work to promote fair, accurate local media coverage of the new rates, including through the preparation and distribution of two press releases about their approval and implementation. The first release, distributed in the period before new rates take effect, would announce the planned rollout of the new rate, provide details about its characteristics, promote awareness of energy efficiency and invite reporters to visit our website or contact a media relations representative for more details. The second would announce the beginning of our implementation of new three-part rates while reinforcing points made in the previous release. Our media relations team also will make itself available to answer any news media questions about the new rates.

Education Outreach – We will incorporate information about new three-part rates and tips for reducing electric demand in our energy efficiency workshops, which are conducted periodically with customer groups in communities across our service territory. These forums provide customers with opportunities for one-on-one interaction with our energy efficiency experts, allowing us to answer unique questions and provide personalized advice for saving energy and money with demand-based rates.

Social Media – We would promote awareness of the new three-part rate online through popular social media channels, including Twitter and Facebook. Questions received on both platforms will be addressed promptly by direct message (Twitter) or publicly available posted responses (on the UES Facebook Page) as appropriate.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

EXHIBIT
UNSE 30
admitted

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

Rejoinder Testimony of

Dallas J Dukes

on Behalf of

UNS Electric, Inc.

February 29, 2016

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Dallas J. Dukes and my business address is 88 East Broadway, Tucson, Arizona, 85702.

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

A. Yes.

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

A. I will respond to the testimony of witness Broderick of Staff, Fulmer of TASC, witness Quinn of AURA, witness Alston of AURA, witness Rubin of AURA, witness Kobor of Vote Solar, witness Huber of RUCO, witness Zwick of ACCA, witness Wilson of Western Resource Advocates, and witness Schlegel of Sweep.

Q. How is your rejoinder testimony organized?

A. In addition to this Introduction, Section 2 provides a summary of the benefits associated with three-part rates and how transitioning to them is in the public interest, Section 3 addresses the bill impacts associated with the proposed three-part rates, as presented its Company's Rejoinder Testimonies, Section 4 address a couple specific positions stated by an Intervenor in Surrebuttal Testimony.

II. PUBLIC INTEREST

Q. Have you reviewed Staff witness Broderick's proposal to provide bill credits or system incentives to DG customers[1]?

A. Yes, I have. Mr. Broderick proposes a 15% bill credit for DG customers before June 1, 2015 and a 15% cost per kW incentive for DG solar installations for the first six months following the completion of the full transition from two-part rates to three-part rates. The Company is proposing some modifications to these proposals as described in the Rejoinder Testimony of Company witness Craig Jones.

Q. Does the Company believe that Mr. Broderick's bill credit proposal for pre June 1, 2015 DG customers is in the public interest?

A. Yes, we believe it would be in the public interest if the Commission approves either (i) a bill credit for pre June 1, 2015 DG customers or (ii) to grandfather these customers under two-part rates in a manner as proposed by the Company in its Direct Testimony.

Q. Several intervening witnesses have asserted that three-part rate design is not in the public's interest or more specifically not in the interest of Residential Customers. Can you please summarize some of the key benefits of three-part rates and how this rate structure is in the public interest?

A. Yes, the Company and many of the Intervenors' witnesses addressing rate design have testified with regards to the many benefits associated with three-part rate design or demand based rates. I will attempt to summarize some of the key points testified to so far in this proceeding.

1. Three-part rates will be beneficial to our customers

[1] Staff Witness Broderick at 6:2-29, 14:2-4

"multi-part rates represent the best practices approach to rates that are just and reasonable, equitable and economically efficient"[2]

"three-part rates, which include a demand charge as well as a fixed charge and an energy charge, do a much better job of reflecting the cost structure of generating and delivering electricity than two-part rates"[3]

"Including a demand charge (in addition to a basic service charge and energy charges) in a retail rate provides customers with rates that better reflect the way utility costs are incurred."[4]

"A demand charge is a proven successful rate design component which better reflects cost causation than rate designs which rely upon energy charges only to recover utility fixed costs. Metering and communications technology improvements, DG penetration, and recent regulatory issues have made its adoption for residential and small general service customers possible, appropriate, timely, and even necessary."[5]

"Staff considered other solutions to the problem caused by shifting fixed costs from vacant, seasonal and distributed generation ("DG") customers. While other solutions would require carving out subclasses and applying measurements to define inclusion or exclusion, Staff's long-term rate design proposal sets the foundation to deal with these concerns without arguing over whether one or more subclasses exist and which customers should be selected for different rates."[6]

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[2] Dr. Overcast Rebuttal at p. 27.
[3] Ahmad Faruqui Surrebuttal at p. 2.
[4] Daniel G. Hansen Direct at p. 4.
[5] Thomas M. Broderick Direct at p. 2.
[6] Howard Solganick Surrebuttal p. 12.

"In fact, demand charges correct the misalignment between a customer's cost of service and their bill inherent in two-part energy rates that rely on a monthly service charge and kWh energy charges to recover the utility's infrastructure investment necessary to serve the home."[7]

"The demand charges proposed by UNSE provide price signals that will inevitably enhance the productivity and efficiency of solar DG. What the fixed charge proposal of UNSE does do is to promote overall system efficiency by tying rates and cost causality more closely together so that marginal rates better reflect actual marginal costs while the fixed rates recover unavoidable fixed costs. This improves the price signals to customers, reduces the degree to which cross subsidies are built into rates (including those that flow from non-solar to solar customers), and makes the actual market value of solar DG and energy efficiency more transparent. In short, the result of both the change in fixed costs and the adoption of demand charges for solar DG customers is to insert the disciplines of market and cost that have been lacking in the past."[8]

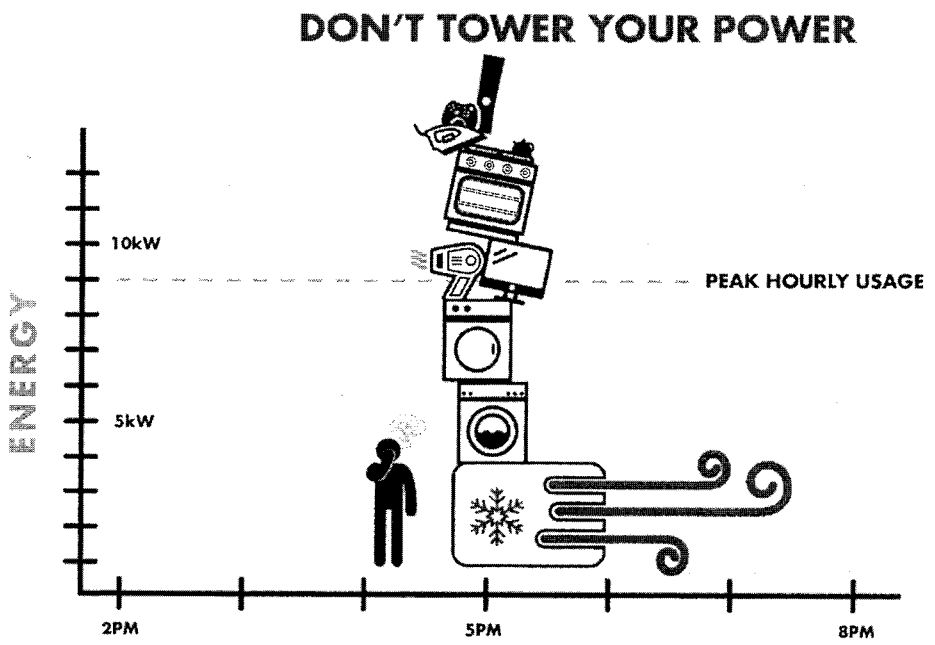
The citations above represent the opinions of nine experts that collectively have over 250 years of professional experience in rate design, cost of service rate-making, utility operations and rate case proceedings. Together, these witnesses testify for the advancement of rate design and support that three-part rates are (i) the best practice approach to rates, (ii) in the public interest and (iii) beneficial to all retail customers.

2. <u>Three-part rates will empower customers to save</u>

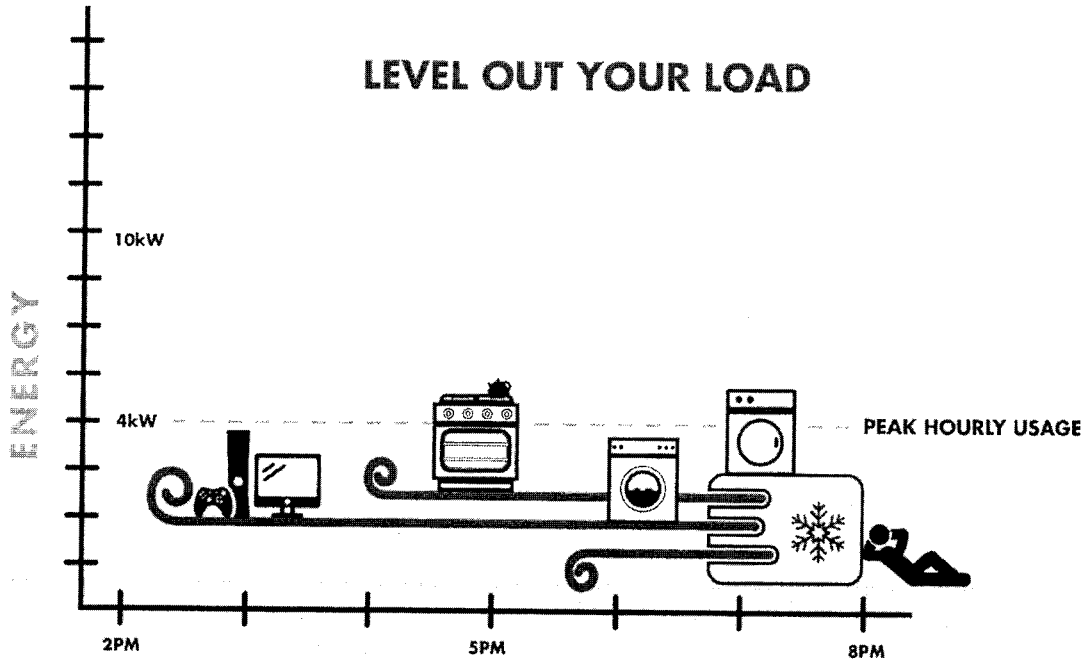
Three-part rates provide price signals to customers that are more closely aligned with how costs are actually incurred in providing safe and reliable electric service. Demand-based rates will provide a real financial incentive to reduce customer peak usage and to

[7] Charles A. Miessner Surrebuttal p. 4.
[8] Ashley C. Brown Surrebuttal p. 23.

use the utility system more efficiently – thus reducing overall system costs, which is clearly in the public interest and beneficial to all customers. And by recovering system costs partially through demand charges and not only through energy charges, the customer then has more options available to them to reduce their monthly bills. They can purchase higher efficiency appliances or household electrical devices, and reduce their energy consumption and thus reduce the cost associated with the energy and demand portions of their bill. They can still adjust their thermostat during peak hours and cycle their air conditioner and furnace less and thus save energy and reduce demand. And/or they can spread out the usage of their higher load appliances – not run their electric clothes dryer during peak hours or at the same time as using their electric stove (even if during peak hours); reducing their highest hourly consumption in those peak hours and the cost associated with that portion of their bill. Below are just a couple of potential illustrations that can be used to assist Customers in this concept.



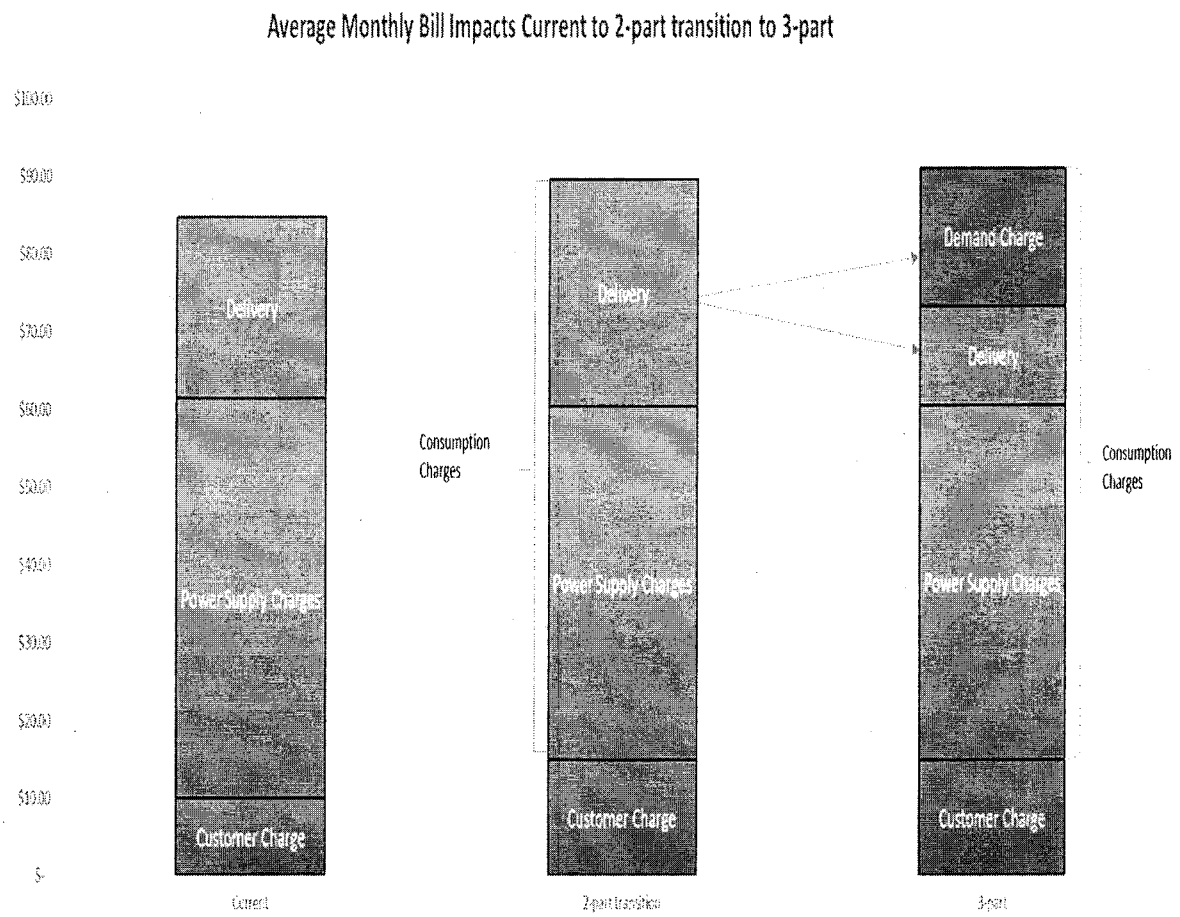
Using multiple electric appliances at the same time will increase the peak hourly usage charge on your monthly bill.



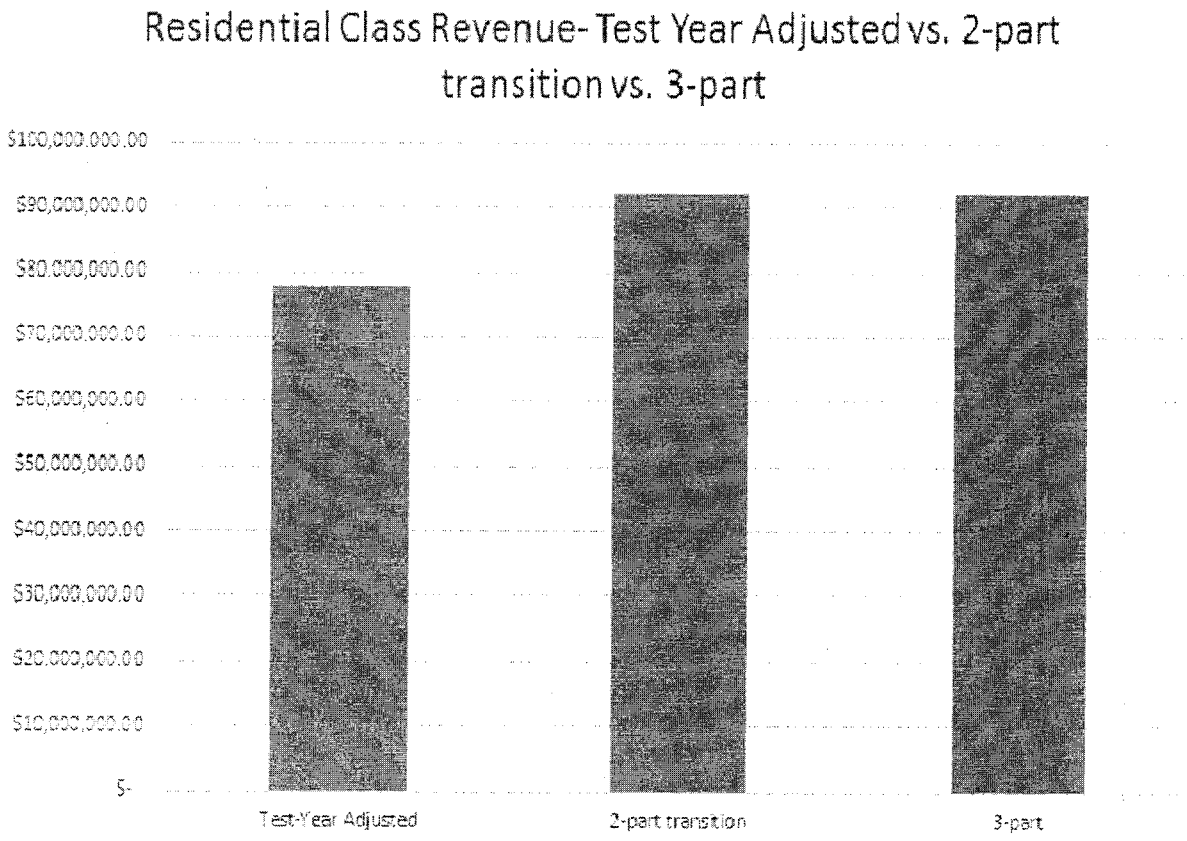
Spreading out your use of appliances during peak usage periods and throughout the day will reduce your peak hourly usage – and lower your bills.

Understand, we are not adding a cost to the customers' bills in the class, we are proposing to split the same cost into two controllable charges. One based upon the accumulated energy used by a customer in a billing period and one based upon the highest energy usage in one hour during peak demand periods. As APS witness Brown stated, "demand charges do not increase rates. They are revenue neutral since the demand costs are already embedded in tariffs. What demand charges do is make those costs transparent, and by doing so, enable all customers, low income included, to shape their demand in ways that can reduce their bill."[9]

[9] Ashley Brown Surrebuttal at p. 8.


Average Monthly Bill Impacts Current to 2-part transition to 3-part
$100.00
$90.00
$80.00
$70.00
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$-
Delivery
Power Supply Charges
Customer Charge
Current
Consumption Charges
Delivery
Power Supply Charges
Customer Charge
2-part transition
Demand Charge
Delivery
Power Supply Charges
Customer Charge
3-part
Consumption Charges

What this means, is that the proposed three-part rate structure is designed to recover the same amount of revenue as a two-part structure, just in a different way.



And under three-part rates, customers will now have an additional way to reduce their bill. In the Direct Testimony of APS witness Miessner, he stated that 60% of a sample of APS' customers on a three-part rate reduced their demand after switching to the three-part rate, with those who actively manage their demand achieving demand savings of 10% to 20% or more.[10] This makes economic sense as customers are given a financial incentive to use electrical equipment differently or at varying times, rather than all at once. It also provide solar DG customers the signal that increasing late afternoon production reduces peak utility demand.

[10] Charles Miessner Direct at p. 7.

3. The proposed three-part rate, as proposed by UNS Electric, is designed specifically to minimize unexpected bill impacts.

The intention of the three-part rate, as proposed by the Company and Staff, is as a transitional structure and has many features specifically included to assure gradualism in rate impacts, rate stability and any unexpected changes. Essentially, the three-part rate proposal is designed very conservatively to the customers' favor by mitigating the chances of adverse impacts (versus our transitional 2-part rate) for our full requirement customers.

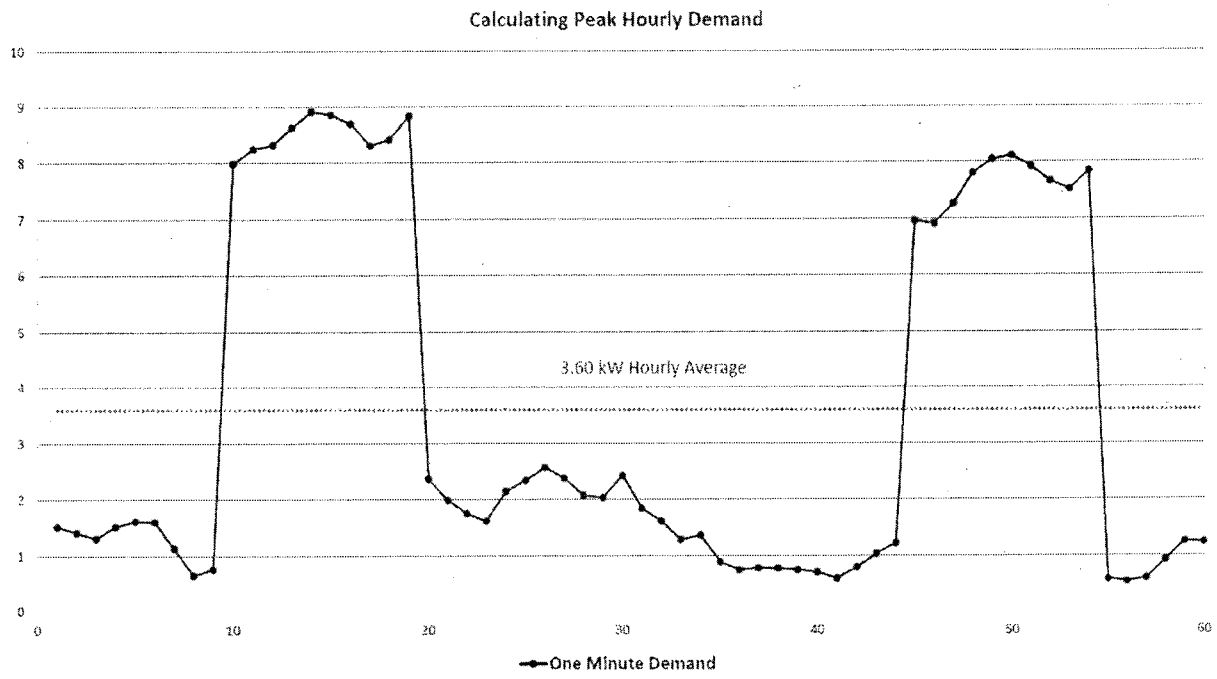
Only customers will atypical usage patterns will see increases on a three-part rate related to how they use the electric grid and the cost to serve them. An incomplete list of these customers includes: partial requirement service, someone using an arc welder during peak hours, or unusually high levels of purely Ohmic heating[11]. These customers will have the opportunity to save by changing their behavior or deploying their dollars into cost effective measures to reduce their demand levels, because they are currently using the system significantly less efficiently than the vast majority of the class. The minimum load factor will help to protect these customers to avoid unexpectedly high bills while it is in effect. But their bills will still show measured demand, showing the demand that could've been used for billing, if not for the minimum load factor. This will give these customers valuable information along with the price signal associated with the billed demand charges, so these customers can modify their usage patterns, if they choose too.

Our typical residential and small general service customers primarily will not see their annual cost of electricity increase simply as a result of migrating to three-part rates, what they will see is greater opportunity to reduce their bill. This is consistent with the foundational principles of proper rate design and is in the public interest and beneficial to

[11] Heating resulting from the passage of an electric current through a resistive material.

our customers. The features put in place to assure this are: measuring the "demand" as the customer's highest hourly usage, limiting this measurement to peak hours only, including just a portion of demand related cost in the demand rate and a load factor floor.[12]

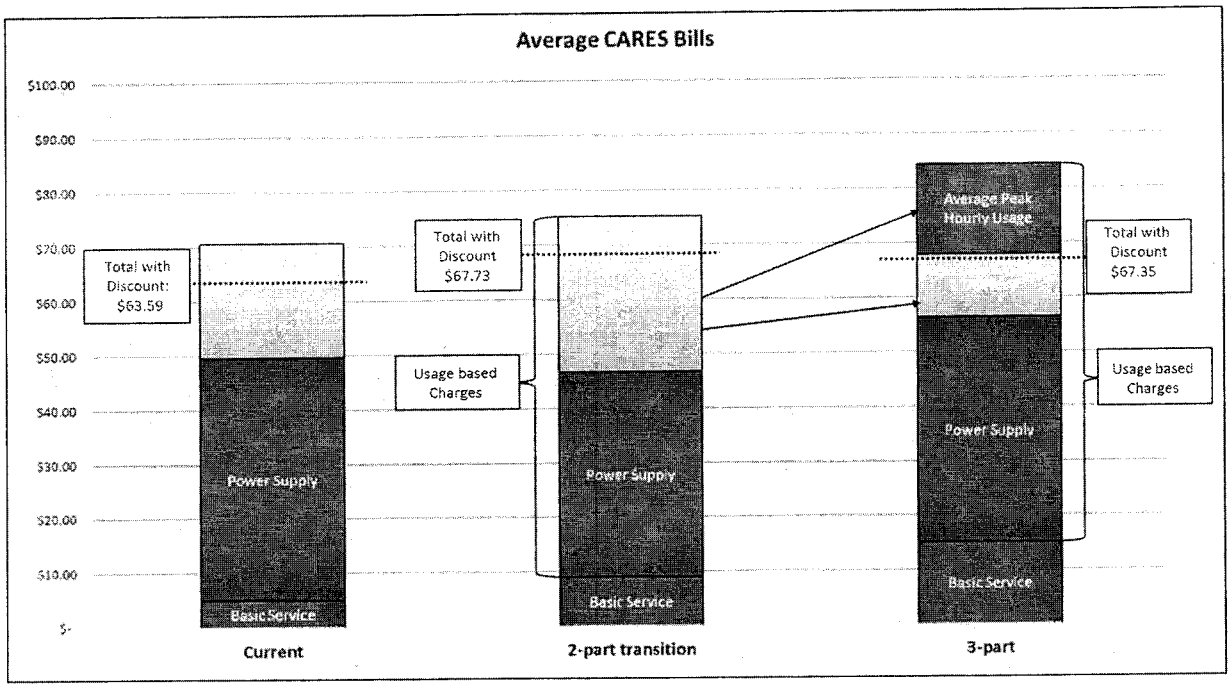
Using an hourly measure for demand alone is a significant mitigating measure, as appliances are rarely used for an entire hour and even when they are, the current draw associated with their usage is cyclical. Below is a chart based on a typical UNS Electric customer, showing their typical peak hour and peak day. You can see if we were using a one minute interval, their demand determinant would be 8.91 kW, using a 15 minute it would be 4.95 kW, but by using a one hour interval the measured demand is 3.60 kW.



[12] Craig Jones Rebuttal at p. 13-15.

4. Three-part rates (as proposed by UNS Electric) will be beneficial to low income customers

Low income customers (CARES customers at UNS Electric) are not by default low usage customers, in fact their usage levels are essentially equivalent to standard residential customers. But more importantly when transitioning to three-part rates, they do have load factors[13] that are equivalent too or even slightly higher than standard residential customers. As such, three-part rates will benefit the CARES customers of UNS Electric. And as discussed above, will give these customers increased options to reduce their bill. As designed by the Company and explained in more detail in the Rejoinder testimony of Craig Jones – CARES customers will receive a $17 flat discount off each month's bill. To the extent they are low usage customers, this specific change to our initially proposed CARES rates will greatly mitigate any impacts associated with the elimination of the artificially low first rate tier included in present rates.



[13] Load factor is defined as the average usage over a period of time divided by the customer's maximum demand (as measured for billing) over the same period of time.

However, and just as importantly, as pointed out be APS witness Ashley Brown, recovering fixed cost more equitably through three-part rates as opposed to two-part will reduce the subsidy presently being provided to customers that can afford to invest in distributed generation ("DG"). In UNS Electric's service territory, less than 0.4% of CARES customers are DG customers, however 2.3% of standard residential customers are – and that number and differential is increasing rapidly. As discussed in Mr. Brown's Surrebuttal Testimony, "Higher income customers are more likely to install rooftop solar, and all other customers, including low income customers, pay the subsidies in question in the form of higher rates. This is, in effect, a wealth transfer from lower income customers to higher income customers. All available analysis indicates that the cross-subsidies inherent in the current suite of net metering and volumetric rate design subsidies transfer wealth from low income customers to high income customers."[14] It is therefore in the public interest, and specifically beneficial to low income customers, to reduce and ultimately eliminate these types of subsidies.

5. Its beneficial to make the transition now and not to delay

Now is the time to move to transitional three-part rates to begin the process of empowering customers with improved price signals and additional bill reduction options. At this time of low market fuel and power cost, resulting in base power and PPFAC rates combined being almost 15% less than they were about two years ago. Customers are in a better position to deal with any learning curve associated with a transition to three-part rates with a moderate demand charge. But, like gasoline prices, natural gas and thus power costs will likely increase over time, so getting the price signals closer to correct will promote the reduction of market purchases during peak times and is clearly in the public interest and beneficial to our customers.

[14] Ashley C. Brown Surrebuttal at p. 5.

In addition, APS witness Ashley Brown addressed the issue of making the transition now and not delaying with his statement: "Moreover, as can already be seen in this state and others, the politics of getting the tariffs right becomes increasingly difficult when more and more people are invested in a severely flawed tariff that skews the prices in costly and economically perverse ways. It is best to get the prices right from the beginning so that when customers make their decision about whether or not to go solar, the price signals are correct and the costs and benefits to society are correctly aligned in the tariff formulation."[15] This statement is true not only for solar, but for any energy technology investment made by customers as a result of skewed price signals.

6. Three-part rates will promote faster advancement of load control technologies, load management programs and customer usage monitoring

By matching cost recovery to cost causation – demand driven cost to demand charges; it is simply logical that monetary price signals rewarding the reduction of peak consumption will provide greater incentive for the advancement of cost effective technologies, additional energy management programs (including behavioral programs) and greater demand for customer access to closer to real time usage information. This is the same conclusion supported by Staff, as testified to by Mr. Solganick. "Customers would have greater information available to make their own energy decisions, and rates would more accurately price those decisions and lessen the consequential impact on other customers."[16] As well as by APS witness Brown, "solar DG providers oppose demand charges and other types of pricing that would enable new energy service providers and vendors to offer consumers products to reduce their energy bills. They are committed to maintaining barriers to new entrants who might offer valuable products and services that provide customers with more options"[17] and "RMI coins a phrase, "flexiwatts," to

[15] Ashley C. Brown Surrebuttal at p. 31.
[16] Howard Solganick Direct p. 12.
[17] Ashley Brown Surrebuttal at p. 10.

describe the services and technology that exist to fill the business space demand charges will offer. A recent RMI blog post hails demand charges as an opportunity for new technologies, customer options, and reduced grid costs"[18] All of which is in the public interest and beneficial to customers.

III. BILL IMPACTS

Q. Do you have revised estimates of how the Company's proposed three-part rate structure and net metering tariff will impact customers?

A. Yes. The table below demonstrates that DG customers will continue to see significant savings under the Company's proposed three-part rate structure and the respective metering proposals by Staff and the Company. The table shows average pre-tax monthly bills for residential full-requirements and DG customers using an average of 500 kWh, 900 kWh, 1,200 kWh, and 1,500 kWh per month.

[18] Ashley Brown Surrebuttal at p. 24.

Monthly Usage	Transitional 2-part Rate: No DG	Proposed 3-part Rate: No DG	Proposed 3-part Rate: DG with Current Net Metering	Proposed 3-part Rate: DG with Proposed Credit for Export
500 kWh per Month				
Average Monthly Bill (pre-tax)	$ 63.66	66.68	$ 31.30	$ 34.79
Bill Savings from 2-part Rate	NA	$ (3.02)	$ 32.36	$ 28.87
Bill Savings from 3-part Rate	NA	NA	$ 35.37	$ 31.89
900 kWh per Month				
Average Monthly Bill (pre-tax)	$ 103.01	$ 103.50	$ 38.88	$ 45.08
Bill Savings from 2-part Rate	NA	$ (0.49)	$ 64.13	$ 57.92
Bill Savings from 3-part Rate	NA	NA	$ 64.62	$ 58.42
1,200 kWh per Month				
Average Monthly Bill (pre-tax)	$ 136.15	$ 130.70	$ 44.45	$ 49.10
Bill Savings from 2-part Rate	NA	$ 5.44	$ 91.69	$ 87.04
Bill Savings from 3-part Rate	NA	NA	$ 86.25	$ 81.60
1,500 kWh per Month				
Average Monthly Bill (pre-tax)	$ 171.09	$ 157.77	$ 49.60	$ 55.99
Bill Savings from 2-part Rate	NA	$ 13.33	$ 121.49	$ 115.11
Bill Savings from 3-part Rate	NA	NA	$ 108.17	$ 101.78

It is evident from the comparisons presented in this table that customers across the usage spectrum with typical load factors will see minimal bill changes from the transitional rate. In actuality, the primary reason a typical low usage customer is seeing a small increase in their monthly bill is as a result of eliminating the artificially low 400 kWh tier present in the two-part volumetric transition rates. For DG customers on the Company's proposed three-part rate structure and net metering tariff will continue to see significant savings when compared to bills under full requirements utility service. For example, a DG customer under the Company's proposed three-part rate and net metering tariff using an average of 900 kWh per month will save $58.42 monthly compared to the Company's proposed full requirements transitional two-part rate and $57.92 compared to the Company's proposed three-part rate. This represents respective monthly bill savings of approximately 56% from full requirements service in both cases.

IV. GENERAL ISSUES

Q. Are there any positions stated in the Surrebuttal Testimonies of Intervenors you would like to specifically address?

A. Yes. There are a couple areas I would like to specifically respond to.

Q. On page 42 of Ms. Kobor's Surrebuttal Testimony, she argues that the proper bill comparisons for residential and small commercial customers should be the movement from the Company's current two-part rates to the Company's proposed three-part rates. Do you have any observations with respect to her position?

A. Yes. I will concentrate on Ms. Kobor's comments with respect to residential customers but my observations can also be applied to her comments on small commercial customers as well. First, I disagree with Ms. Kobor that the proper bill impact comparison should be the movement from the Company's current rates to the proposed three-part rates. When it is used by her in the context of rate impacts being driven by the migration to three-part rate design and ignoring that we are requesting a revenue increase. Because the reality is that when a utility must recover more cost from fewer units of sale – even maintaining two-part rates will result in bill increases. On a purely percentage basis, those customers presently enjoying very low bills will see higher percentage increases as fixed cost recovery is better aligned with cost causation – even in two-part rate design.

Nevertheless, the Company is presenting its bill impact schedules with Rejoinder Testimony (see CAJ-RJ-1) showing the movement from current two-part rates to proposed three-part rates. However, these schedules will show bill impacts that incorporate adjustments the Company has made since Rebuttal and the numbers will differ slightly from those submitted with Rebuttal. Therefore, the remainder of my observations will use

the rates submitted in the Company's Rebuttal case, so as to be apples-to-apples with Ms. Kober's analysis.

Q. On page 42 of her Surrebuttal Testimony, Ms. Kobor identifies the residential bill impact of moving from current rates to the Company's proposed three-part rate as 16%.[19] Do you agree?

A. No. Ms. Kobor misstates the impact by using a simple mean of monthly average bill changes from the Company's sample of 2,306 residential customers. Ms. Kobor's use of a simple mean here does not represent an "average bill impact," but represents a simple mean of customer average monthly bill impacts. A customer with an average monthly bill of $20 who experiences a $5 monthly bill increase sees an increase of 25%. Conversely, a customer with a $200 monthly bill who experiences a $10 monthly bill increase sees an increase of 5%. However, taking a simple mean of these two customer bill impacts yields an average monthly bill increase of 15%.[20] Obviously, using a simple mean of average impacts will bias the result toward the observations with the smaller base bills, in this case the customer with the original bill of $20, and observations with smaller kWh usage. The proper way to look at bill impacts is to calculate bills with different rate structures at different usage levels and then compare the results for equivalent usage levels. I have calculated the residential bill impacts in moving from current rates to the Company's proposed rebuttal three-part rates, including the proposed non-fuel revenue increase, for monthly usage levels of 200 kWh, 500 kWh, 795 kWh, 900 kWh, 1,200 kWh, and 1,500 kWh and they are presented in the table below. The results for 795 kWh are presented in bold because that is the mean monthly kWh usage level for the sample.

[19] Kobor Surrebuttal at 42:7.
[20] The simple mean is obtained by adding 25% to 5% and dividing by 2.

Monthly Bill Impacts of Rebuttal 3-part Rates to Current Rates

Average Monthly Usage	Average Monthly Load Factor	Billing kW	Monthly Bill with Current Rates	Monthly Bill with Proposed 3-Part Rates	Change ($)	Change (%)
200 kWh	19.9%	1.37	$ 26.56	$ 33.39	$ 6.83	25.7%
500 kWh	23.6%	2.90	$ 52.92	$ 62.41	$ 9.49	17.9%
795 kWh	**25.7%**	**4.24**	**$ 81.79**	**$ 90.08**	**$ 8.29**	**10.1%**
900 kWh	26.3%	4.69	$ 92.05	$ 99.79	$ 7.74	8.4%
1,200 kWh	27.7%	5.93	$ 122.25	$ 127.31	$ 5.06	4.1%
1,500 kWh	28.9%	7.11	$ 152.85	$ 154.52	$ 1.67	1.1%

It is obvious from table that the average customer bill impact will be nowhere near 16%. For the sample mean of 795 kWh per month, the bill impact of moving from current rates to the proposed three-part rates is estimated to be $8.29, or 10.1%, for the Company's Rebuttal case. Also, keep in mind that $5.00 of the $8.29 increase is due solely to the proposed $5.00 increase in the Basic Service Charge. Therefore, only the remaining $3.29, is because of the movement to a three-part demand rate, without the artificially low 400 kWh block rate and of course with the remaining rate increase (at the Rebuttal level).

Q. On page 43 of her Surrebuttal Testimony, Ms. Kobor presents two figures that purport to give the story of the bill impacts of moving from current rates to proposed three-part rates. Do you have any comments on these figures?

A. Yes. Ms. Kobor concentrates only on the percentage change in monthly customer bills for the intervals presented. This approach suffers from the same bias that I noted in my example earlier. If the sample contains customers with low usage levels and low load factors, these customers will show bill impacts with large percentage increases even though the changes in dollar terms may be deemed reasonable to begin the transition to a more cost based rate structure.

Q. On page 44 of her Surrebuttal Testimony, Ms. Kobor states that "nearly 88% of residential customers are expected to see bill increases under the UNSE proposal, with nearly one in five customers expected to have their monthly bills increase by more than 30%."[21] How do you respond?

A. Ms. Kobor laments the fact that nearly 88% of residential customers are expected to see a bill increase in the move from current rates to the proposed three-part rates, but the fact of the matter is that 100% of the customers sampled will see an increase in the movement from current two-part rates to transitional two-part rates because of the requested increase in the Company's non-fuel revenues. To identify three-part rates as the culprit for bill increases is very misleading.

With respect to nearly one in five customers in the sample seeing a monthly bill increase of more than 30%, my previous discussion stands. While some customers may see monthly increases in the range of 30%, the dollar impacts associated with them are typical of increases some customers will see in a rate case using an historical test year, with declining billing determinants (fewer energy sales) and the inclusion of a major new asset into rate base. Some customers incurring more significant percentage increases than others is unavoidable within a class of customers having varying system usage patterns. I calculated the number of customers in the sample that would see monthly bill increases above 30% and arrived at 358, or 15.5%, of the 2,309 sampled. The average monthly bill increase for these customers would be $10.11 (from current rates and based on our **Rejoinder** position), which is due to (1) the $5 increase in the Basic Service Charge, (2) the non-fuel revenue increase, and (3) as a result of eliminating the artificially low 400 kWh rate block. This increase is not a result of the movement to three-part rates.

[21] Kobor Surrebuttal at 44:1-2.

I should note that a minimum bill approach, as suggested by a number of Intervenors, including Ms. Kober, if designed to recover anything approaching an appropriate level of fixed cost recovery, would have similar if not greater percentage impacts for a significant proportion of customers bills. Recall from my direct testimony that one of four residential bills issued was for 300 kWh or less. Any meaningful minimum bill would produce very large percentage increases as it relates to these bills versus present rates. For example, if you assumed a minimum bill were to be set at only $20 (which I would not view as meaningful), a zero consumption customer would see a 100% bill increase from UNS Electric's present standard residential rate.

Q. On page 44 of her Surrebuttal Testimony, Ms. Kobor has a discussion of the Company's proposed minimum load factor adjustment. Do you have any comments?

A. Ms. Kobor states that because the minimum load factor adjustment is proposed to be a temporary measure, bill impacts will only increase when it is removed.[22] Once again, this argument is consistent with those of many interveners in this case who oppose three-part demand rates for residential and small commercial rate classes, namely that utility customers are unsophisticated and cannot learn. The heretofore absence of three-part rates in the residential and small commercial rate classes has been because of the lack of sophistication in metering technology, not a lack of customer understanding. Three-part demand rates have been a staple of utility ratemaking for years and there is no reason to suspect that residential and small commercial customers cannot become educated and adept at managing their bills under three-part rate design. The minimum load factor adjustment should be considered as analogous to training wheels on a bicycle. Just because you take them off after a period of practicing doesn't mean you automatically fall over, never to get up again. I would also add that the minimum load factor will provide information that will allow the Company to target customer communications and programs

[22] Kobor Surrebuttal at 44:21-25.

such as: educational materials, load management programs, assistance programs and other customer outreach to directly assist these customers during this transition period to empower them to improve their load factors and to use the system more efficiently and thus lower their bills.

Q. Does this conclude your Testimony?

A. Yes, it does.