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BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
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COMMISSIONER
BOB BURNS
COMMISSIONER
TOM FORESE
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ANDY TOBIN
COMMISSIONER

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AZ CORP COMMISSION
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IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.

Docket No. E-04204A-15-0142

Arizona Corporation Commission
DOCKETED
FEB 23 2016
DOCKETED BY

RUCO'S NOTICE OF FILING

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the Surrebuttal Testimony of Robert Mease, Jeffrey Michlik and Lon Huber, in the above-referenced matter.

RESPECTFULLY SUBMITTED this 23rd day of February, 2016.

Daniel W. Pozefsky
Chief Counsel

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UNS ELECTRIC, INC.

DOCKET NO. E-04204A-15-0142

SURREBUTTAL TESTIMONY

OF

ROBERT MEASE

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

FEBRUARY 23, 2016

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EXECUTIVE SUMMARY

The Residential Utility Consumer Office's ("RUCO") has reviewed UNS Electric, Inc.'s ("UNSE") rebuttal testimony filed in regards to its application for a permanent rate increase, filed with the Arizona Corporation Commission ("ACC" or "Commission") on May 4, 2015, and RUCO recommends the following:

<u>Cost of Equity</u> – RUCO recommends that the Commission adopt a 9.13 percent cost of common equity. RUCO's recommendation of 9.13 percent is the result obtained from the Discounted Cash Flow model ("DCF") the Capital Asset Pricing Model ("CAPM") and the Comparable Earnings Mode ("CEM")l. RUCO included a Comparable Earnings Model in Its rebuttal testimony only and was not included in direct testimony. The Company's cost of capital witness continues to recommend a cost of equity of 10.35 percent even though the Company has agreed with 9.50 percent return that is being recommended by Staff and also is UNSE's current rate of return on common equity.

<u>Cost of Debt</u> – RUCO recommends that the Commission adopt the actual cost of long-term debt of 4.66 percent which is UNSE's actual end of test year cost of long-term debt. This compares to the cost of debt previously approved in Decision No. 74235 of 5.47 percent.

<u>Capital Structure</u> – RUCO recommends that the Commission adopt UNSE's actual end of test year capital structure comprised of no short-term debt, 47.17 percent long-term debt and 52.83 percent common equity.

<u>Original Cost Rate of Return</u> – RUCO recommends that the Commission adopt a 7.17 percent weighted average cost of capital as the original cost rate of return for UNSE. This compares to the Company's requested weighted average original cost of capital of 7.67 percent.

<u>Fair Value Rate of Return</u> – RUCO recommends that the Commission adopt a fair value rate of return of 5.48 percent for UNSE, which is RUCO's 7.02 percent original cost rate of return minus RUCO's recommended inflation adjustment of 1.54 percent. The method used by RUCO to arrive at this 7.02 percent figure is consistent with the methods adopted by the Arizona Corporation Commission in prior UNSE and UNS Gas, Inc. rate case proceedings.

INTRODUCTION

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

A. My Name is Robert B. Mease. I am the Chief of Accounting and Rates for the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Have you previously provided testimony regarding this docket?

A. Yes. I filed testimony in this docket on November 5, 2015.

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony will address the Company's rebuttal proposals and comments pertaining to adjustments I recommended in my direct testimony. I will also briefly discuss other intervening parties who addressed cost of capital issues in this filing and will present additional adjustments that are being made by RUCO to supplement what was proposed in direct testimony.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Please summarize the recommendations and adjustments that you will address in your surrebuttal testimony.

A. Based on the results of my analysis, I am making the following recommendations:

Cost of Equity Capital – I am revising my initial cost of equity from 8.35 percent and now recommending that the Commission adopt a 9.13 percent cost of common equity. The 9.13 percent figure is the result obtained from my cost of equity analysis after the inclusion a CEM and updates and revisions to both the CAPM and DCF models.

Cost of Debt – RUCO is recommending that the Commission adopt the Company's end of test year cost of long-term debt of 4.66 percent. This compares favorably to the Company's previous rate application where the cost of long-term debt was approved at 5.47 percent.

Capital Structure – I am recommending that the Commission adopt UNSE's actual end of test year capital structure comprised of 52.83 percent common equity and 47.17 percent long-term debt. The Company has no short-term debt.

Original Cost Rate of Return – I am recommending that the ACC adopt a 7.17 percent weighted average cost of capital as the original cost rate of return ("OCROR") for UNSE. This 7.17 percent figure is the weighted cost of RUCO's recommended costs of common equity and debt, and is 59 basis points lower than the 7.72 percent weighted average cost of capital being proposed by the Company.

Fair Value Rate of Return – I am recommending that the Commission adopt a fair value rate of return ("FVROR") of 5.48 percent which is my recommended 7.02 percent OCROR minus an inflation adjustment of 1.54 percent.

Q Why do you believe that RUCO's recommended 7.02 percent OCROR and 5.48 percent FVROR are appropriate rates of return for UNSE to earn on its invested capital?

A. Both the OCROR and FVROR figures that I am recommending for UNSE meet the criteria established in the landmark Supreme Court cases of <u>Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia</u> (262 U.S. 679, 1923) and <u>Federal Power Commission v. Hope Natural Gas Company</u> (320 U.S. 391, 1944).

RUCO'S COST OF EQUITY CAPITAL

Q. What is your final recommended cost of equity capital for UNSE?

A. I am recommending a cost of equity of 9.13 percent. My cost of equity recommendation is slanted towards the high side of the range of results derived from my DCF and CAPM analyses and I have also prepared a Comparable Earnings Analysis and included the results in my final calculations.

Discounted Cash Flow (DCF) Method

Q. Is the DCF model an acceptable methodology used in ratemaking for public utilities?

A. Yes. Basically the DCF model, is one of the oldest and most utilized models in determining the cost of equity in many utility hearings. In a 2014 rate case filing by Potomac Electric Power, in Washington, D.C., the commission relied primarily on a DCF analysis to arrive at the authorized ROE, "finding that the DCF method produces results more reasonable than those of other calculation methods."[1] While the DCF model is the most widely used and accepted model, including Arizona, it should be supplemented with at least one additional model to add additional support to the final cost of equity calculation.

Q. Have you made changes to your DCF model that was filed in your direct testimony?

A. Yes. I've made modifications resulting from updates to published data from Value Line, I've reduced the number of proxy companies by two, as a result of recent mergers, that were used for comparative purposes and I've "tweaked" several on the inputs that were part of my original DCF model as filed in direct testimony.

[1] See EEI Report, page 29

Capital Asset Pricing Model (CAPM) Method

Q. Can you please describe the CAPM and the benefits of preparing this analysis?

A. The CAPM describes the relationship between a security's investment risk and its market rate of return. This relationship identifies the rate of return which investors expect a security to earn so that its market return is comparable with the market returns earned by other securities that have similar risk.

Q. Can you please identify the strengths of using the CAPM model in your analysis?

A. The strengths of the CAPM are as follows: (1) it is based on the concept of risk and return; (2) it is company specific as it relates to the specific beta's within the industry; (3) it has widespread use as it recognizes that investors can and do diversify; (4) it's highly structured and easy to apply when using the assumptions of the model; (5) the model is formulistic and the data used in the computations is readily available; (6) it is a forward looking concept; and (7) it is a method for converting changes in interest rates to the cost of equity.

Q. What are the results of your CAPM analysis?

A. As shown on pages 1 and 2 of Schedule RBM-6, my CAPM calculation using an arithmetic mean results in an average expected return of 6.84

percent and the results of using a geometric mean is 7.07 percent. I used an average of the geometric and arithmetic means in my final determination for RUCO's cost of equity recommendation.

Q. Have you made changes to your CAPM that was filed in your direct testimony?

A. Yes. I made updates and revisions to the CAPM included in this filing for the same reasons as identified on page 6 in this filing related to the DCF model revisions.

Comparable Earnings Model (Analysis)

Q. Can you please explain the purpose of a comparable earnings analysis and what companies were included in performing your analysis?

A. The CEM analysis is basically used for comparative purposes in analyzing returns expected to be earned on the original cost and book value of companies with similar risks. The companies used in my CEM are the same proxy companies that were included in my DCF and CAPM models.

Q. What period of time did you analyze and include in your analysis?

A. I used actual earnings for the years 2002 through 2014 and projected earnings as published in Value Line for the years 2015 through and including year 2020.

Q. Please summarize the results derived under each of the methodologies presented in your testimony.

A. The following is a summary of the cost of equity capital derived under each methodology used:

METHOD	RESULTS
DCF	8.33% -- 10.12%
CAPM	6.84% -- 7.07%
CEM	8.75% -- 10.00%

Based on these results, my best estimate of an appropriate range for a cost of common equity for the Company is 8.00 percent to 10.00 percent and RUCO's final cost of equity recommendation is 9.13 percent. Included in my calculation for the CAPM, I used an average of both the arithmetic and geometric means as sophisticated investors have access to both and that both are included in investment decisions. See RBM-3 for calculations.

Q. Can you provide a comparison of the results derived from Ms. Bulkley's models and yours?

	Company Witness	RUCO
DCF – Constant Growth	9.04% – 10.35%	8.33 % -- 10.12%
DCF – Multi-Stage	9.30% -- 9.92%	
CAPM	9.59% -- 11.10%	6.84% -- 7.07%
CEM		8.75% -- 10.00%

UNSE's / STAFF's / RUCO's PROPOSED COST OF EQUITY CAPITAL

Q. Have you reviewed UNSE's rebuttal testimony on the Company-proposed cost of equity capital?

A. Yes, I have reviewed the testimony of the Company's cost of equity expert witness, Ms. Ann Bulkley.

Q. Can you please compare Ms. Bulkley's cost of equity as filed in UNSE's original application to the cost of equity as recommended in the Company's rebuttal testimony?

A. Yes. Ms. Bulkley recommended a cost of equity of 10.35 percent in the Company's initial filing and continues to recommend 10.35 in her rebuttal testimony. However, she goes on to say on page 79 of her rebuttal testimony that "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. And what is Staff's cost of equity recommendation in this case?

A. As indicated in Mr. Abinah's testimony, Staff's cost of capital witness, "Staff recommends that the Commission grant UNS Electric, Inc. a 9.50 percent cost of equity and 0.50 percent fair value increment. This is the same cost of equity and fair value increment awarded UNSE in Commission Decision No. 74235, issued on December 31, 2013."

Q. Isn't this somewhat unusual for Staff to adopt a cost of equity that is a holdover from the prior rate case decision?

A. Yes, while it is unusual it does happen on occasion. RUCO has also adopted a previous approved cost of equity when the case was decided within several months prior to the newer filing and it happened to be within the same parent company.

Q. Can you briefly describe the last rate case as filed by UNSE and the final decision as it relates to cost of equity and final rate of return?

A. Yes I will. The last rate case filed by UNSE had a test year ending June 30, 2012 and the final decision was issued on December 31, 2013. The cost of capital witness in that case for UNS, Ms. Bulkley, recommended a cost of equity of 10.50 percent. The cost of capital witness for the Staff had developed a cost of equity between the ranges of 8.50 percent to 10 percent and a final recommendation for cost of equity of 9.25 percent. Staff witness also recommended the final capital structure including the cost of debt that was included in the capital structure as filed by the company and approved in the final decision.

Q. What was the Commission's final decision reached in Docket No. E-04204A-12-0504?

A. The Company, Staff and RUCO reached a settlement agreement that provided for a 9.50 cost of equity as well as the final overall fair value rate of return of 6.02. The Commission determined that the settlement agreement reached by the parties was just, fair and reasonable and was adopted in the final Decision No. 74235.

Q. Was RUCO surprised when Staff witness agreed to accept the cost of equity as recommended in the last rate case?

A. Yes, particularly since the test year in that case ended on June 30, 2012, approximately three and one-half years ago. As previously stated, accepting a prior cost of equity return from a previous decision has only occurred in very few circumstances and I'm not aware of any situation where the prior filing was in excess of three and a half years since the case was filed and in excess of two years since the case was decided.

Q. Was UNSE witness Ms. Bulkley, critical of RUCO's cost of equity recommendations in this case?

A. Yes. Ms. Bulkley was critical of RUCO's recommendations as well as the recommendations of TASC, Wal-Mart and Staff. She didn't approve of any cost of capital recommendations except for those included in her direct and rebuttal testimonies.

Q. What is your overall general response to Ms. Buckley's comments related to deficiencies she discusses in her rebuttal testimony?

A. In general, I understand that any cost of equity consultants (i.e. expert witnesses) will have differences between methodologies utilized in calculating cost of equity. Each methodology possesses its own way of examining investor behavior and no one 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. In other words, you could ask ten expert witnesses to determine the cost of equity in a given rate case application and there will be ten different conclusions.

Q. Can you be more specific as to those disagreements with RUCO?

A. The Company witness(s) identified the following areas of disagreement with RUCO's cost of capital recommendations; (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 of companies; and (6) His FVROR recommendation and the method used to derive that recommendation.

Q. What is your response to the criticisms as discussed by Ms. Bulkley related to RUCO's conclusions?

A. I am not going to address each of the areas of disagreement except to say that both the DCF and CAPM models have been updated with the latest information as provided by Value Line and Yahoo Finance, the proxy group of companies have changed as a result of two mergers, and a CEM has now been included as part of RUCO's final cost of equity calculation. As a result of these updates and revisions RUCO is now recommending a cost of equity of 9.13 percent.

Q. What about her comment of RUCO's failure to consider the higher business and regulatory risk which UNS Electric is exposed?

A. I do not agree with this comment. I've heard this comment many times in past rate cases but in this case it just simply does not relate. On page 6 of

Mr. Hutchins testimony he addresses the recent reduction in debt cost, constructive regulatory outcomes, steady improvement in UNS Electric's financial condition and a strong credit rating and favorable market conditions. When reading Mr. Hutchins testimony it's really a stretch to say that UNS Electric has a higher business and regulatory risk as those companies included as proxy companies in this case.

Q. Have you updated your cost of equity models from your direct testimony?

A. Yes, I've made adjustments to my DCF and CAPM models and have also included a CEM.

ECONOMIC ENVIRONMENT

Current Economics Surrounding the Electric Utilities

Q. Did EEI publish information on rate case applications that member companies have been involved in for year 2014?

A. Yes. Investor-owned electric utilities filed 58 rate cases in 2014. The average requested ROE was the lowest requested in their history and the awarded ROE was the lowest in their data base reaching back to 1990.

Q. Has there been updates published by EEI for rate case activity related to investor-owned members for year 2015?

A. Yes. EEI publishes rate case activity each quarter and having reviewed all four quarters for year 2015 there were forty-eight rate cases filed and the authorized ROE's continue to drop to record low levels.

Q In the EEI 2014 annual report was there any mention of the purchase of UNS by Fortis?

A. Yes. "UNS said joining Fortis enhances the financial strength of its local utility operations, and provides additional support for long-term investment."

General Economic Conditions

Q. Please explain why it is necessary to consider the current economic environment when performing a cost of equity capital analysis for a regulated utility.

A. Consideration of the economic environment is necessary because trends in interest rates, present and projected levels of inflation, and the overall state of the U.S. economy determine the rates of return that investors earn on their invested funds.

Q. Can you please explain how general economic and financial conditions are considered in the determination of the cost of capital for a public utility?

A. Yes. The cost of capital is determined in part by the current and future economic and financial conditions. The level of economic activity; the stage of the business cycle; the trend in interest rates, and the level of inflation or expansion all play an important factor in determining the cost of capital. While there are other factors involved these are the most important and at any point in time each can have an influence on the cost of capital.

Q. What is the current outlook for the economy?

A. Interest rates were increased in December 2015 for the first time since December 2008. The reasons given by the Federal Open Market Committee ("FOMC") for increasing the interest at this time were improvement in the labor market conditions during 2015, confidence that inflation will rise to 2 percent level and that the economic activity will continue to expand at a moderate pace and labor market indicators will continue to strengthen.

Q. Since the increase in interest rates by the FOMC has the market reacted as expected?

A. I don't believe it has. When reviewing the Press Release date December 26, 2015, it appears that the FOMC is skeptical of increasing interest rates again going forward. "In determining the timing and size of future adjustments to the target range for the federal funds rate, the Committee will assess realized and expected economic conditions relative to its objectives of maximum employment and 2 percent inflation. This assessment will take into account a wide range of information, including measures of labor market conditions, indicators of inflation pressures and inflation expectations, and reading on financial and international developments. In light of the current shortfall of inflation from 2 percent, the Committee will carefully monitor actual and expected progress toward its inflation goal. The Committee, expects that economic conditions will evolve in a manner that will warrant only gradual increases in the federal funds rate; the federal funds rate hike is likely to remain, for some time, below levels that are expected to prevail in the longer run."

Q. Have you read other publications discussing future inflation rates?

A. Yes. In reading the Federal Reserve Bank of San Francisco, FRBSF Fed Views, January 14, 2016, publication they are projecting inflation in year 2016 between one percent and one and one-half percent and rise gradually towards the 2 percent target as the effects of transitory shocks to energy prices and the exchange rate dissipate and as improving labor market conditions strengthen wage growth.

Q. Why do you believe that further increases in the short term may be skeptical?

A. Assuming that 2 percent inflation factor is a principle factor in further increases it could very well be several years before we see another increase in interest rates. When the interest rate was increased in December, 2015, the inflation rate was less than one percent, however, it was believed by some that the interest rates were increased for other reasons i.e. liquidity trap." (That's when families and businesses hoard cash instead of spending it. Low interest rates don't give either much incentive for investments).

Q. How has Arizona fared in terms of the overall economy and home foreclosures?

A. Arizona was one of the states hit hardest during the Great Recession and has lagged during the current recovery. During the period between 2006 and 2009, statewide construction spending fell by 40.00 percent. According to information provided by Irvine, California-based RealtyTrac, Arizona was ranked third in the nation behind California and Nevada in terms of home foreclosures with the largest number of foreclosures occurring in Maricopa, Pinal and Pima Counties.

Q. What is the current unemployment situation in Arizona during this period of economic recovery?

A. According to information published on October 30, 2015, the seasonally adjusted unemployment rate for Arizona has increased from 6 percent in April, 2015, to 6.3 percent in September, 2015. This compare the national unemployment rate of 5.1 percent for the period ending in September, 2015. For the year ending December 31, 2015, the unemployment rate in Arizona was published as 6 percent and continues to recover well below the national average. I believe it is safe to say that Arizona's economy is recovering at a much slower pace that the national average.

COST OF DEBT AND CAPITAL STRUCTURE

Q. What cost of long-term debt are you recommending for UNSE?

A. I am recommending that the Commission adopt UNSE's actual end of test year cost of long-term debt of 4.66 percent.

Q. Please describe the Company-proposed capital structure.

A. The Company is proposing an adjusted end of test year capital structure comprised of no short-term debt, 47.17 percent long-term debt and 52.83 percent common equity.

Q. How does the Company-proposed capital structure compare with the capital structures of the electric companies that comprise your sample?

A. The Company-proposed capital structure, Schedule RBM-2, is virtually identical to the average capital structure of the electric companies included in my sample.

Q. What capital structure are you recommending for UNSE?

A. I am recommending that the Commission adopt the Company's actual end of test year capital structure comprised of zero short-term debt, 47.17 percent long-term debt and 52.83 percent long-term common equity, which is essentially the same as the capital structure being proposed by UNSE.

WEIGHTED COST OF CAPITAL AND FAIR VALUE RATE OF RETURN

Q. What original cost weighted average cost of capital are you recommending for UNSE?

A. Based on my recommended capital structure, comprised of 47.17 percent long-term debt and 52.53 percent common equity, I am recommending an original cost weighted average cost of capital of 7.17 percent, Schedule RBM-1. This is the weighted average cost of my recommended cost of long-term debt of 4.66 percent and my recommended 9.13 percent cost of common equity.

Q. What fair value rate of return are you recommending for UNSE?

A. I am recommending a FVROR of 5.48 percent, RBM-1, which is 154 basis points lower than my OCROR of 7.02 percent. My recommended FVROR satisfies the fair value requirement of the Arizona Constitution which the Commission must follow when setting rates for investor owned utilities such as UNSE.

Q. Why are you recommending a FVROR that is different from your OCROR?

A. Because UNSE elected not to use the Company's original cost rate base ("OCRB") as its fair value rate base ("FVRB") in this case. Instead, UNSE performed a reconstruction cost new less depreciation ("RCND") study to restate the value, or reproduction cost, of the Company's OCRB. As is the normal ratemaking practice in Arizona, the Company averaged the values of its OCRB and its RCND rate base to arrive at a FVRB that is higher than the OCRB. This is because the value of the FVRB reflects the impact of inflation and other factors which tend to contribute to an upward growth in value over time. Since the difference in the value of the OCRB and the FVRB represents inflation, as opposed to additional investor supplied capital, an OCROR which includes an inflation component cannot be applied to the FVRB. To do so would result in a double counting of inflation. For this reason it is necessary to remove the inflation component that is included in the OCROR.

OTHER CONSIDERATIONS

Q. Has RUCO considered any other options in this case for their recommended cost of common equity?

A. Yes. RUCO would consider recommending the same for cost of common equity as both the Company and ACC Staff seem to have agreed too provided the overall revenue requirement is not greater than $15.1 million.

Q. What has the Company and Staff agreed to at this point?

A. The Company has agreed with Staff's recommendation of 9.50 percent cost of common equity and the inclusion of a 50 basis points as fair value increment which is the same as authorized in the last rate case decision. However, the Company qualified their acceptance of the Staffs proposal as follows; "As long as the overall revenue increase and rate design approved for UNS Electric provides the Company with a reasonable opportunity to actually earn a 9.5% return on equity, the Company would not oppose to the adoption of Staff's recommended values."[2]

Q. Why would RUCO consider recommending the same cost of equity as the Staff recommended and the Company appears to have accepted?

A. There are several reasons why RUCO would accept this proposal. First, after making several revisions to update the DCF and CAPM models,

[2] Rebuttal testimony of Kentton C. Grant, Pg. 8, Line 23

based on the latest information available from Value Line and Yahoo Finance, coupled with the inclusion of a CEM the difference between RUCO's final recommendation and the cost of common equity as approved in the last rate case has been reduced substantially. Second and foremost, RUCO understands that the recent revision to the accounting order pending approved by the Commission in Docket No. E-04204A-13-0476 will lower the revenue increase by approximately $3 million. That will effectively reduce UNSE's increase in revenues requested in this rate case from the Company's original request of $22.6 million. RUCO believes that the approximate $7.5 million overall reduction in total revenue increase coupled with the many issues surrounding the overall rate design, is in the best interest of ratepayers to come to agreement.

Q. Does RUCO believe that their acceptance of the cost of equity and fair value adjustment in this case bounds RUCO to the same in rate cases going forward?

A. Absolutely not. If RUCO agrees with this position in this case it does not presuppose that RUCO will recommend or agree to this return on equity or fair value increment in future rate case applications.

Q. Does this conclude your testimony on UNSE?

A. Yes, it does.

ATTACHMENT A

UNS Electric, Inc.
Test Year Ended December 31, 2014
Docket No. E-04204A-15-0142

SCHEDULE #

RBM - 1	WEIGHTED AVERAGE COST OF CAPITAL
RBM - 2	COST OF LONG TERM AND SHORT TERM DEBT
RBM - 3	COST OF COMMON EQUITY
RBM - 4	FAIR VALUE ADJUSTMENT
RBM - 5	DCF COST OF EQUITY CAPITAL
RBM - 6	CAPM COST OF EQUITY CAPITAL
RBM - 7	PROXY GROUP'S COMPARABLE EARNINGS ANALYSIS

ATTACHMENTS

A	REVISED SCHEDULES
B	VALUE LINE REPORTS - UPDATES
C	YAHOO FINANCE ANALYSTS REPORTS / STOCK PRICES

UNS Electric, Inc.
Test Year Ended December 31, 2014
Docket No. E-04204A-15-0142

Schedule RBM-1

WEIGHTED AVERAGE COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) CAPITALIZATION PER COMPANY	(B) RUCO ADJUSTMENTS	(C) RUCO ADJUSTED CAPITALIZATION	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST
1	Long - Term Debt	$ 169,590	$ -	$ 169,590	47.17%	4.66%	2.20%
2	Short - Term Debt	-	-	-	-	-	-
3	Common Equity	189,932	-	189,932	52.83%	9.13%	4.82%
4	TOTAL CAPITALIZATION	$ 359,522	$ -	$ 359,522	100.00%		7.02%
5	Fair Value Adjustment						0.15%
6	**ORIGINAL COST WEIGHTED AVERAGE COST OF CAPITAL**						7.17%

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1; SCHEDULE RBM-2
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COLUMN (C) LINE 1 ÷ COLUMN (C), LINE 4
COLUMN (E): LINE 1 - COMPANY SCHEDULE D-1; SCHEDULE RBM-2
COLUMN (E): LINE 3 - SCHEDULE RBM-3
COLUMN (F): COLUMN (D) x COLUMN (E)

FAIR VALUE WEIGHTED AVERAGE COST OF CAPITAL

LINE NO.		(A) CAPITALIZATION	(B) RUCO	(C) RUCO ADJUSTED	(D) CAPITAL	(E) COST	(F) WEIGHTED COST
7	LONG-TERM DEBT	$ 169,590	$ -	$ 169,590	47.17%	3.12%	1.47%
8	COMMON EQUITY	189,932	-	189,932	52.83%	7.59%	4.01%
9	TOTAL CAPITALIZATION	$ 359,522	$ -	$ 359,522	100.00%		5.48%
10	COLUMN (A) THROUGH (D) SEE ABOVE						
11	COLUMN (E), LINE 7 SEE RBM-2						

UNS Electric, Inc.
Test Year Ended December 31, 2014
Docket No. E-04204A-15-0142

Schedule RBM-2

COST OF LONG TERM and SHORT TERM DEBT (thousands of US dollars)

LINE NO.	LONG TERM DEBT DESCRIPTION	End of Test Year (Actual) (A) Actual as of DEC. 31, 2014	(B) Annual Interest	(C) Annual Cost Rate Long Term Debt	End of Test Year (Proposed) (D) Proposed as of DEC. 31, 2014	(E) Annual Interest	(F) RUCO ADJUSTED BALANCE
	Fixed Rate Debt:						
1	6.50% Senior Unsecured Notes due 08/15	$ 50,000	$ 3,250	6.50%	$ -	$ -	$ -
2	7.10% Senior Unsecured Notes Series B due 08/23	50,000	3,550	7.10%	50,000	3,550	7.10%
3	3.22% Senior Unsecured Notes Series A due 08/27	-	-	-	80,000	2,576	3.22%
4	3.95% Senior Unsecured Notes Series B due 04/45	-	-	-	50,000	1,975	3.95%
5	Total Fixed Rate Debt	100,000	6,800	6.80%	180,000	8,101	4.50%
6	**Variable Rate Debt:**						
7	4 Year Term Loan due 08/15	30,000	629	2.10%	-	-	-
8	Total Variable Rate Debt	30,000	629	2.10%	-	-	-
9	**Total Long-Term Debt (Ln 5 + Ln 8)**	$ 130,000	$ 7,429	5.71%	$ 180,000	$ 8,101	4.50%
10	**Unamortized Debt Discount, Premium**						
11	Expense and Loss on Reacquired Debt	(410)	-		(1,246)		
12	**Amortization of Debt Discount and**						
13	Expense and Loss on Reacquired Debt	-	182		-	169	
14	**Credit Facility Commitment Fee**	-	51		-	63	
15	**Total Long Term Debt - Net of expenses (Ln 9 less Ln 11, 13, 14)**	129,590	7,662		178,754	$ 8,333	
16	**Total Cost Long Term Debt (Col. B / Col. A) (Col. E / Col. F)**			5.91%			4.66%
	SHORT TERM DEBT						
17	Revolving Line of Credit	$ 40,000	$ 513	1.28%	$ -	$ -	$ -
18	Total Debt Actual - End of Test Year	$ 169,590	$ 8,175	4.82%			
19	Total Debt Proposed - End of Test Year				$ 178,754	$ 8,333	4.66%
20	LESS: RECOMMENDED FAIR VALUE INFLATION ADJUSTMENT						-1.54%
21	COST OF LONG-TERM DEBT - FAIR VALUE (LINE 19 - LINE 20)						3.12%

COST OF COMMON EQUITY ESTIMATE

LINE NO.			
1	DCF METHODOLOGY		
2	DCF - SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	8.33% - 10.12%	SCHEDULE RBM-5
3	CAPM METHODOLOGY		
4	CAPM - GEOMETRIC MEAN ESTIMATE	7.07%	SCHEDULE RBM-6, PAGE 1 OF 2
5	CAPM - ARITHMETRIC MEAN ESTIMATE	6.84%	SCHEDULE RBM-6, PAGE 2 OF 2
6	COMPARABLE EARNINGS	8.75% - 10.00%	SCHEDULE RBM-7
7	RANGE OF DCF, CAPM ARITHEMETIC / GEOMETRIC MEANSA AND CEM ESTIMATES	8.00% - 10.00%	AVERAGE OF LINES 2 THROUGH 6
8	FINAL RUCO RECOMMENDED COST OF COMMON EQUITY	9.13%	TESTIMONY, RBM
9	LESS: RECOMMENDED FAIR VALUE INFLATION ADJUSTMENT	-1.54%	SCHEDULE RBM-4
10	COST OF COMMON EQUITY ESTIMATE - FAIR VALUE	7.59%	LINE 8 - LINE 9

UNS Electric, Inc.
Test Year Ended December 31, 2014
Docket No. E-04204A-15-0142

SCHEDULE RBM-4

INFLATION ADJUSTMENT TO RUCO'S RECOMMENDED ORIGINAL COST OF EQUITY CAPITAL

LINE NO.	(A) YEAR	(B) VALUE TIPS	(C) VALUE BONDS	(D) DIFFERENCE
1	2009	1.66%	3.26%	1.61%
2	2010	1.15%	3.22%	2.06%
3	2011	0.55%	2.78%	2.23%
4	2012	0.42%	1.78%	1.36%
5	2013	0.80%	2.10%	1.30%
6	2014	0.49%	1.60%	1.11%
7	2015	0.10%	1.20%	1.10%
8				
9	**RECOMMENDED FAIR VALUE INFLATION ADJUSTMENT - AVERAGE COLUMN (D)**			**1.54%**

REFERENCES

COLUMNS (A) THRU (C), LINES 1 THRU 9: FEDERAL RESERVE BANK
COLUMN (D): COLUMN (C) - COLUMN (D)
COLUMNS (B) THRU (D), LINE 10: AVERAGE OF LINES 1 THRU 7
COLUMN (D), LINE 11: TESTIMONY - RBM

UNS Electric, Inc.
Test Year Ended December 31, 2014
Docket No. E-04204A-15-0142

SCHEDULE RBM-5

DCF 90 DAY CONSTANT GROWTH

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) FIVE YEAR GROWTH YAHOO FINANCE	(G) AVERAGE EARNINGS GROWTH	(H) ROE LOW	(I) ROE MEAN	(J) ROE HIGH
1	ALE	ALLETE, Inc.	$ 2.02	/	50.48	=	4.00%	4.12%	6.50%	5.00%	5.75%	9.10%	9.87%	10.63%
2	AEP	American Electric Power Company	$ 2.24	/	57.02	=	3.93%	4.02%	5.00%	4.55%	4.78%	8.57%	8.80%	9.03%
3	EE	EL Paso Electric	$ 1.18	/	38.31	=	3.08%	3.16%	3.50%	7.00%	5.25%	6.63%	8.41%	10.19%
4	EDE	Empire District Electric Company	$ 1.04	/	25.32	=	4.11%	4.19%	3.00%	5.00%	4.00%	7.17%	8.19%	9.21%
5	ES	Eversource Energy	$ 1.67	/	50.83	=	3.29%	3.41%	8.50%	6.57%	7.54%	9.96%	10.94%	11.92%
6	GXP	Great Plains Energy Inc.	$ 1.05	/	26.88	=	3.91%	4.00%	5.00%	5.07%	5.04%	9.00%	9.04%	9.07%
7	IDA	IDACORP, Inc.	$ 2.04	/	66.88	=	3.05%	3.09%	1.00%	4.00%	2.50%	4.07%	5.59%	7.11%
8	OTTR	Otter Tail Corporation	$ 1.23	/	26.52	=	4.65%	4.82%	9.00%	6.00%	7.50%	10.79%	12.32%	13.86%
9	PNW	Pinnacle West Capital Corporation	$ 2.50	/	62.94	=	3.97%	4.06%	4.00%	4.95%	4.48%	8.05%	8.54%	9.02%
10	PNM	PNM Resources, Inc.	$ 0.88	/	29.22	=	3.01%	3.15%	9.00%	9.30%	9.15%	12.15%	12.30%	12.45%
11	POR	Portland General Electric Company	$ 1.20	/	36.44	=	3.29%	3.38%	6.00%	4.13%	5.07%	7.49%	8.44%	9.39%
13	WR	Westar Energy, Inc.	$ 1.44	/	41.54	=	3.47%	3.55%	6.00%	3.50%	4.75%	7.03%	8.30%	9.57%
		AVERAGE					**3.65%**	**3.75%**	**5.54%**	**5.42%**	**5.48%**	**8.33%**	**9.23%**	**10.12%**

AVERAGE OF LOW, MEAN AND HIGH **9.23%**

REFERENCES:
COLUMN (A); ANNUALIZED DIVIDENDS PER VALUE LINE
COLUMN (B): AVERAGE STOCK PRICES, SEE TESTIMONY ATTACHMENT (C)
COLUMN (C): COLUMN (A) / COLUMN (B)
COLUMN (D): COLUMN (C) X (1+.05 COLUMN (G))
COLUMN (G) AVERAGE COLUMN (E) AND (F)

UNS Electric, Inc.
Test Year Ended December 31, 2014
CAPM COST OF EQUITY CAPITAL

BASED ON A GEOMETRIC MEAN:

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) k	=	r_f	+ [	ß	x (	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	ALE	ALLETE, Inc.	k	=	2.50%	+ [	0.80	x (	12.00%	-	6.10%	)]	=	7.22%
2	AEP	American Electric Power Company	k	=	2.50%	+ [	0.70	x (	12.00%	-	6.10%	)]	=	6.63%
3	EE	EL Paso Electric	k	=	2.50%	+ [	0.75	x (	12.00%	-	6.10%	)]	=	6.93%
4	EDE	Empire District Electric Company	k	=	2.50%	+ [	0.70	x (	12.00%	-	6.10%	)]	=	6.63%
5	ES	Eversource Energy	k	=	2.50%	+ [	0.75	x (	12.00%	-	6.10%	)]	=	6.93%
6	GXP	Great Plains Energy Inc.	k	=	2.50%	+ [	0.85	x (	12.00%	-	6.10%	)]	=	7.52%
7	IDA	IDACORP, Inc.	k	=	2.50%	+ [	0.80	x (	12.00%	-	6.10%	)]	=	7.22%
8	OTTR	Otter Tail Corporation	k	=	2.50%	+ [	0.85	x (	12.00%	-	6.10%	)]	=	7.52%
9	PNW	Pinnacle West Capital Corporation	k	=	2.50%	+ [	0.75	x (	12.00%	-	6.10%	)]	=	6.93%
10	PNM	PNM Resources, Inc.	k	=	2.50%	+ [	0.80	x (	12.00%	-	6.10%	)]	=	7.22%
11	POR	Portland General Electric Company	k	=	2.50%	+ [	0.80	x (	12.00%	-	6.10%	)]	=	7.22%
12	WR	Westar Energy, Inc.	k	=	2.50%	+ [	0.75	x (	12.00%	-	6.10%	)]	=	6.93%
13														
14														
15														
16														
17	**AVERAGE**						$\boxed{0.78}$							**7.07%**

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$k = r_f + [\,ß\,(r_m - r_f)\,]$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = 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

UNS Electric, Inc.
Test Year Ended December 31, 2014
CAPM COST OF EQUITY CAPITAL

BASED ON AN ARITHMETIC MEAN:

LINE NO.	STOCK SYMBOL	COMPANY NAME	k	=	r_f	+ [	ß (A)	x (	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	ALE	ALLETE, Inc.	k	=	2.50%	+ [	0.80	x (	12.00%	-	6.40%	)]	=	6.98%
2	AEP	American Electric Power Company, Inc.	k	=	2.50%	+ [	0.70	x (	12.00%	-	6.40%	)]	=	6.42%
3	EE	EL Paso Electric	k	=	2.50%	+ [	0.75	x (	12.00%	-	6.40%	)]	=	6.70%
4	EDE	Empire District Electric Company	k	=	2.50%	+ [	0.70	x (	12.00%	-	6.40%	)]	=	6.42%
5	ES	Eversource Energy	k	=	2.50%	+ [	0.75	x (	12.00%	-	6.40%	)]	=	6.70%
6	GXP	Great Plains Energy Inc.	k	=	2.50%	+ [	0.85	x (	12.00%	-	6.40%	)]	=	7.26%
7	IDA	IDACORP, Inc.	k	=	2.50%	+ [	0.80	x (	12.00%	-	6.40%	)]	=	6.98%
8	OTTR	Otter Tail Corporation	k	=	2.50%	+ [	0.85	x (	12.00%	-	6.40%	)]	=	7.26%
9	PNW	Pinnacle West Capital Corporation	k	=	2.50%	+ [	0.75	x (	12.00%	-	6.40%	)]	=	6.70%
10	PNM	PNM Resources, Inc.	k	=	2.50%	+ [	0.80	x (	12.00%	-	6.40%	)]	=	6.98%
11	POR	Portland General Electric Company	k	=	2.50%	+ [	0.80	x (	12.00%	-	6.40%	)]	=	6.98%
12	WR	Westar Energy, Inc.	k	=	2.50%	+ [	0.75	x (	12.00%	-	6.40%	)]	=	6.70%
13	**AVERAGE**						**0.78**							**6.84%**

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$$k = r_f + [\, ß\,(r_m - r_f)\,]$$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = 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

UNS Electric, Inc.
Test Year Ended December 31, 2014
CAPM COST OF EQUITY CAPITAL

PROXY COMPANY'S - COMPARABLE EARNINGS COMPUTATION
RATES OF RETURN ON COMMON EQUITY

	Company	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2018 - 2020	2002 - 2020
ALE	ALLETE, Inc.	12.4%	11.9%	11.9%	11.3%	11.6%	11.8%	10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	9.0%	8.0%	9.0%	9.6%
AEP	American Electric Power Company, In	12.3%	12.4%	12.7%	11.9%	12.2%	11.7%	11.6%	11.0%	9.3%	10.7%	9.7%	9.9%	10.2%	12.1%	10.0%	10.0%	11.1%
EE	EL Paso Electric				6.6%	10.6%	11.2%	11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	9.3%	8.0%	8.5%	9.5%	9.9%
EDE	Empire District Electric Company	8.4%	8.7%	5.7%	6.2%	9.2%	6.9%	7.4%	7.5%	7.4%	8.1%	7.9%	8.6%	8.8%	7.5%	7.5%	9.5%	7.8%
ES	Eversource Energy				5.1%	4.3%	8.4%	9.6%	9.2%	9.8%	9.8%	5.7%	8.2%	8.2%	8.5%	9.0%	9.5%	8.1%
GXP	Great Plains Energy Inc.	15.6%	16.6%	16.9%	13.7%	9.8%	10.6%	5.9%	4.9%	7.3%	5.8%	6.2%	7.3%	6.8%	6.0%	7.5%	7.5%	9.3%
IDA	IDACORP, Inc.	7.1%	4.2%	8.2%	7.3%	9.4%	7.1%	8.0%	9.3%	9.8%	10.5%	9.9%	10.1%	9.9%	9.0%	9.0%	8.5%	8.6%
OTTR	Otter Tail Corporation	15.2%	12.0%	10.8%	11.6%	10.4%	10.4%	5.9%	3.7%	2.1%	2.7%	6.9%	9.4%	11.6%	10.0%	11.0%	12.5%	9.1%
PNW	Pinnacle West Capital Corporation	8.6%	8.3%	8.2%	6.7%	9.2%	8.5%	6.1%	6.8%	9.3%	8.7%	9.8%	9.9%	9.5%	9.5%	9.5%	10.0%	8.7%
PNM	PNM Resources, Inc.	6.3%	6.7%	7.9%	8.6%	8.4%	3.4%	0.5%	3.1%	4.8%	5.8%	6.6%	6.9%	7.1%	7.0%	7.5%	9.5%	6.3%
POR	Portland General Electric Company				5.3%	5.9%	11.5%	6.5%	6.2%	8.0%	9.0%	8.3%	7.7%	9.0%	8.0%	9.0%	9.5%	8.0%
WR	Westar Energy, Inc.	5.0%	10.6%	7.7%	9.6%	11.1%	10.0%	6.7%	6.3%	8.6%	8.2%	9.5%	9.8%	9.9%	9.5%	9.5%	9.5%	8.8%
	Mean	10.1%	10.2%	10.0%	8.7%	9.3%	9.3%	7.5%	7.0%	7.9%	8.5%	8.3%	8.8%	9.0%	8.7%	8.8%	9.5%	8.78%
	Median	8.6%	10.6%	8.2%	8.0%	9.6%	10.2%	7.1%	6.7%	8.3%	8.7%	8.2%	9.0%	9.2%	8.8%	9.0%	9.5%	8.75%

Source: AUS Utility Reports and Value Line Investment Survey.

ATTACHMENT B

ALLETE NYSE-ALE

RECENT PRICE **50.15** | P/E RATIO **14.2** (Trailing: 15.3; Median: 16.0) | RELATIVE P/E RATIO **0.81** | DIV'D YLD **4.1%** | VALUE LINE

TIMELINESS 3 Raised 4/24/15
SAFETY 2 New 10/1/04
TECHNICAL 2 Raised 12/18/15
BETA .80 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	37.5	51.7	49.3	51.3	49.0	35.3	37.9	42.5	42.7	54.1	58.0	59.7
Low:	30.8	35.7	42.6	38.2	28.3	23.3	30.0	35.1	37.7	41.4	44.2	45.3

Target Price Range 2018 | 2019 | 2020

2018-20 PROJECTIONS

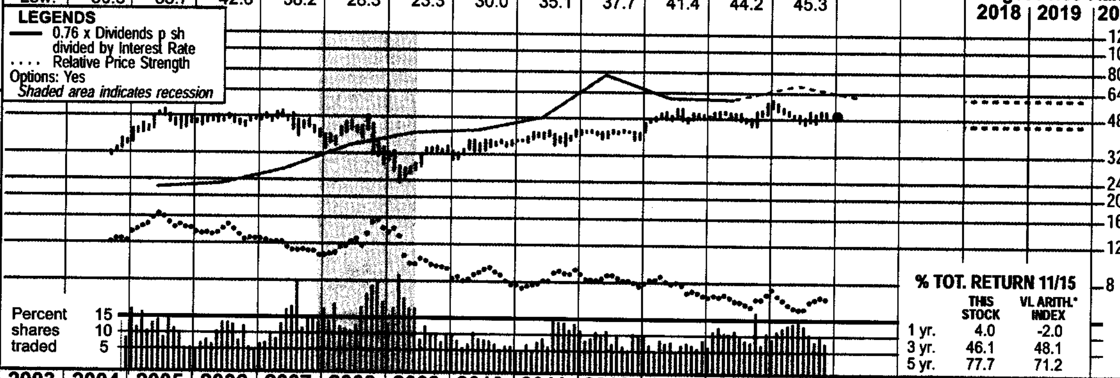
	Price	Gain	Ann'l Total Return
High	60	(+20%)	9%
Low	45	(-10%)	2%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	1	0	0	0	0	1	0
to Sell	0	1	2	1	1	1	0	3	1

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	117	117	90
to Sell	77	79	100
Hld's(000)	33487	35643	35552



LEGENDS
— 0.76 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession

% TOT. RETURN 11/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	4.0	-2.0
3 yr.	46.1	48.1
5 yr.	77.7	71.2

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
--	--	--	--	--	25.30	24.50	25.23	27.33	24.57	21.57	25.34	24.75	24.40	24.60	24.77	*30.60*	*28.45*	Revenues per sh	*33.50*
--	--	--	--	--	2.97	3.85	4.14	4.42	4.23	3.57	4.35	4.91	5.01	5.35	5.68	*6.50*	*6.40*	"Cash Flow" per sh	*7.75*
--	--	--	--	--	1.35	2.48	2.77	3.08	2.82	1.89	2.19	2.65	2.58	2.63	2.90	*3.50*	*3.20*	Earnings per sh A	*4.00*
--	--	--	--	--	.30	1.25	1.45	1.64	1.72	1.76	1.76	1.78	1.84	1.90	1.96	*2.02*	*2.08*	Div'd Decl'd per sh B ■ †	*2.30*
--	--	--	--	--	2.12	1.95	3.37	6.82	9.24	9.05	6.95	6.38	10.30	7.93	12.48	*5.70*	*4.75*	Cap'l Spending per sh	*5.50*
--	--	--	--	--	21.23	20.03	21.90	24.11	25.37	26.41	27.26	28.78	30.48	32.44	35.06	*37.50*	*38.70*	Book Value per sh C	*43.50*
--	--	--	--	--	29.70	30.10	30.40	30.80	32.60	35.20	35.80	37.50	39.40	41.40	45.90	*49.00*	*49.25*	Common Shs Outst'g D	*50.00*
--	--	--	--	--	25.2	17.9	16.5	14.8	13.9	16.1	16.0	14.7	15.9	18.6	17.2	*Bold figures are*		Avg Ann'l P/E Ratio	*13.0*
--	--	--	--	--	1.33	.95	.89	.79	.84	1.07	1.02	.92	1.01	1.05	.91	*Value Line*		Relative P/E Ratio	*.80*
--	--	--	--	--	.9%	2.8%	3.2%	3.6%	4.4%	5.8%	5.0%	4.6%	4.5%	3.9%	3.9%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $1598.1 mill. **Due in 5 Yrs** $411.9 mill.
LT Debt $1549.0 mill. **LT Interest** $64.4 mill.
(LT interest earned: 4.0x)
Leases, Uncapitalized Annual rentals $13.4 mill.

Pension Assets-12/14 $544.2 mill.
Oblig. $714.5 mill.
Pfd Stock None

Common Stock 48,965,562 shs.

MARKET CAP: $2.5 billion (Mid Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
737.4	767.1	841.7	801.0	759.1	907.0	928.2	961.2	1018.4	1136.8	*1500*	*1400*	Revenues ($mill)	*1675*
68.0	77.3	87.6	82.5	61.0	75.3	93.8	97.1	104.7	124.8	*165*	*155*	Net Profit ($mill)	*195*
28.4%	37.5%	34.8%	34.3%	33.7%	37.2%	27.6%	28.1%	21.5%	22.6%	*20.0%*	*20.0%*	Income Tax Rate	*20.0%*
.4%	1.4%	6.6%	5.8%	12.8%	8.9%	2.7%	5.3%	4.4%	6.3%	*3.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
39.1%	35.1%	35.6%	41.6%	42.8%	44.2%	44.3%	43.7%	44.6%	44.2%	*43.5%*	*42.5%*	Long-Term Debt Ratio	*41.0%*
60.9%	64.9%	64.4%	58.4%	57.2%	55.8%	55.7%	56.3%	55.4%	55.8%	*56.5%*	*57.5%*	Common Equity Ratio	*59.0%*
990.6	1025.6	1153.5	1415.4	1625.3	1747.6	1937.2	2134.6	2425.9	2882.2	*3260*	*3330*	Total Capital ($mill)	*3675*
860.4	921.6	1104.5	1387.3	1622.7	1805.6	1982.7	2347.6	2576.5	3286.4	*3675*	*3750*	Net Plant ($mill)	*4075*
8.0%	8.6%	8.6%	6.7%	4.8%	5.4%	6.0%	5.6%	5.3%	5.2%	*6.0%*	*5.5%*	Return on Total Cap'l	*6.5%*
11.3%	11.6%	11.8%	10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	*9.0%*	*8.0%*	Return on Shr. Equity	*9.0%*
11.3%	11.6%	11.8%	10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	*9.0%*	*8.0%*	Return on Com Equity E	*9.0%*
5.2%	5.0%	5.8%	3.9%	.5%	1.5%	2.9%	2.3%	2.2%	2.5%	*4.0%*	*3.0%*	Retained to Com Eq	*3.5%*
54%	57%	51%	61%	93%	81%	66%	71%	72%	67%	*57%*	*66%*	All Div'ds to Net Prof	*59%*

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	+1.1	-1.1	+.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.24	5.45	6.09
Capacity at Peak (Mw)	1790	1793	1985
Peak Load, Winter (Mw) F	1633	1646	1637
Annual Load Factor (%)	79.0	NA	NA
% Change Customers (avg.)	+.5	NA	NA
Fixed Charge Cov. (%)	341	306	345

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-.5%	--	*5.5%*
"Cash Flow"	6.0%	5.5%	*6.5%*
Earnings	7.0%	1.0%	*6.5%*
Dividends	NMF	2.0%	*3.0%*
Book Value	4.5%	5.0%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2012	240.0	216.4	248.8	256.0	961.2
2013	263.8	235.6	251.0	268.0	1018.4
2014	296.5	260.7	288.9	290.7	1136.8
2015	320.0	323.3	462.5	*394.2*	*1500*
2016	*345*	*340*	*360*	*355*	*1400*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2012	.66	.39	.78	.75	2.58
2013	.83	.35	.63	.82	2.63
2014	.80	.40	.97	.73	2.90
2015	.85	.46	1.23	*.96*	*3.50*
2016	*.90*	*.45*	*1.00*	*.85*	*3.20*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.445	.445	.445	.445	1.78
2012	.46	.46	.46	.46	1.84
2013	.475	.475	.475	.475	1.90
2014	.49	.49	.49	.49	1.96
2015	.505	.505	.505	.505	

BUSINESS: ALLETE, Inc. is the parent of Minnesota Power, which supplies electricity to 146,000 customers in northeastern MN, & Superior Water, Light & Power in northwestern WI. Electric rev. breakdown: taconite mining/processing, 27%; paper/wood products, 9%; other industrial, 7%; residential, 12%; commercial, 13%; wholesale, 10% other, 22%. ALLETE Clean Energy owns renewable energy projects. Acq'd U.S. Water Services 2/15. Has real estate operation in FL. Generating sources: coal & lignite, 56%; wind, 7%; other, 3%; purchased, 34%. Fuel costs: 31% of revs. '14 deprec. rate: 2.9%. Has 1,600 employees. Chairman, President & CEO: Alan R. Hodnik. Inc.: MN. Address: 30 West Superior St., Duluth, MN 55802-2093. Tel.: 218-279-5000. Internet: www.allete.com.

ALLETE's earnings will almost certainly wind up significantly higher in 2015, thanks to a development fee for the construction of a wind project. The company's ALLETE Clean Energy subsidiary is building a wind project that it is selling to a utility in North Dakota. The company booked a progress payment that boosted profits by $0.25 a share in the third quarter, and the final payment should add another $0.12 a share or so in the December period. Because the project management has been even stronger than expected, and Minnesota Power (ALLETE's main utility subsidiary) has cut expenses through a cost-reduction program, management raised its share-earnings target for the year from $3.20-$3.40 to $3.35-$3.50. We have raised our share-net estimate by $0.20, so it now stands at the upper end of the company's guidance.

We think earnings will decline in 2016. The comparisons will be difficult in the second half of the year because of the boost provided by the aforementioned wind project fees. In addition, activity by Minnesota Power's taconite customers has waned. (Taconite is used in steelmaking.) These large electricity users had been running at full capacity for the past several years, but are now expecting 80% of full-demand levels for the first four months of 2016. The utility might be able to make up for part of the shortfall through additional wholesale power sales. The one positive factor for the year-to-year comparisons is that the company's purchase of U.S. Water, which provides water management services to industrial customers, should be more accretive to income next year once some amortizations cease after the first quarter. Our earnings estimate is within ALLETE's targeted range of $3.10-$3.40 a share.

We think the board of directors will raise the annual dividend by $0.06 a share (3.0%) in the first period of 2016. This has been the pattern in recent years. ALLETE is targeting a payout ratio in a range of 60%-65%.

This stock's dividend yield is slightly above the utility mean. Total return potential to 2018-2020 is only average for the group, however.

Paul E. Debbas, CFA *December 18, 2015*

(A) Diluted EPS. Excl. nonrec. gain (loss): '04, 2¢; '05, ($1.84); gain (losses) on disc. ops.: '04, $2.57, '05, (16¢); '06, (2¢); loss from accounting change: '04, 27¢. Next egs. report due mid-Feb. (B) Div'ds historically paid in early Mar., June, Sept. and Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred chgs. In '14: $7.78/sh. (D) In mill. (E) Rate base: Orig. cost deprec. Rate allowed on com. eq. in '10: 10.38%; earned on avg. com. eq., '14: 8.6%. Reg. Clim.: Avg. (F) Summer peak in '12 & '13.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	35
Earnings Predictability	80

AMERICAN ELEC. PWR. NYSE-AEP

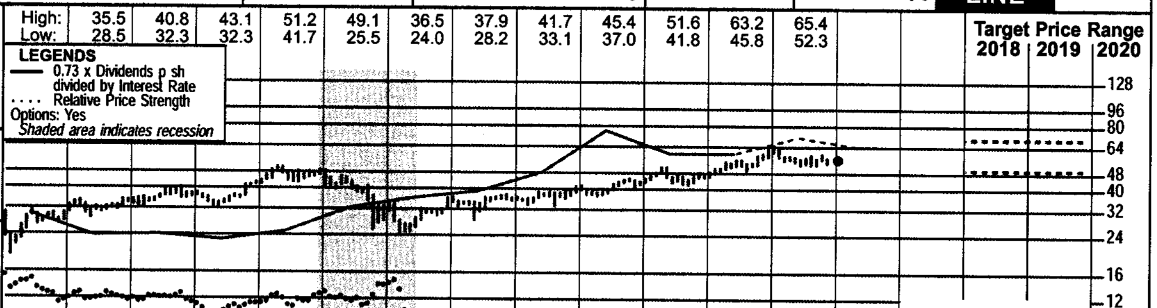
RECENT PRICE 55.88 | P/E RATIO 15.8 (Trailing: 15.4 / Median: 13.0) | RELATIVE P/E RATIO 0.90 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 3 Lowered 6/12/15
SAFETY 2 Raised 9/19/14
TECHNICAL 2 Raised 12/18/15
BETA .70 (1.00 = Market)

High:	35.5	40.8	43.1	51.2	49.1	36.5	37.9	41.7	45.4	51.6	63.2	65.4
Low:	28.5	32.3	32.3	41.7	25.5	24.0	28.2	33.1	37.0	41.8	45.8	52.3

Target Price Range 2018 | 2019 | 2020

LEGENDS
— 0.73 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+25%)	10%
Low	50	(-10%)	2%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	10	0	0	0	0
to Sell	0	1	0	0	4	0	0	3	0

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	338	327	328
to Sell	368	336	317
Hld's(000)	324222	328262	332965

Percent shares traded 15 10 5

% TOT. RETURN 11/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	1.1	-2.0
3 yr.	47.9	48.1
5 yr.	95.2	71.2

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
35.63	42.53	190.10	42.96	36.82	35.51	30.76	31.82	33.41	35.56	28.22	30.01	31.27	30.77	31.48	34.78	**33.95**	**34.40**	Revenues per sh	**37.75**
6.36	5.11	7.65	6.99	5.76	5.89	5.96	6.67	6.80	6.84	6.32	6.29	6.83	6.92	7.02	7.57	**8.10**	**8.35**	"Cash Flow" per sh	**9.25**
2.69	1.04	3.27	2.86	2.53	2.61	2.64	2.86	2.86	2.99	2.97	2.60	3.13	2.98	3.18	3.34	**3.70**	**3.70**	Earnings per sh A	**4.25**
2.40	2.40	2.40	2.40	1.65	1.40	1.42	1.50	1.58	1.64	1.64	1.71	1.85	1.88	1.95	2.03	**2.15**	**2.27**	Div'd Decl'd per sh B ■	**2.65**
4.47	5.51	5.69	5.08	3.44	4.28	6.11	8.89	8.88	9.83	6.19	5.07	5.74	6.45	7.75	8.68	**9.75**	**10.45**	Cap'l Spending per sh	**8.50**
25.79	25.01	25.54	20.85	19.93	21.32	23.08	23.73	25.17	26.33	27.49	28.33	30.33	31.37	32.98	34.37	**36.00**	**37.50**	Book Value per sh C	**42.25**
194.10	322.02	322.24	338.84	395.02	395.86	393.72	396.67	400.43	406.07	478.05	480.81	483.42	485.67	487.78	489.40	**492.00**	**494.00**	Common Shs Outst'g D	**500.00**
14.3	34.3	13.9	12.7	10.7	12.4	13.7	12.9	16.3	13.1	10.0	13.4	11.9	13.8	14.5	15.9	*Bold figures are*		Avg Ann'l P/E Ratio	**14.0**
.82	2.23	.71	.69	.61	.66	.73	.70	.87	.79	.67	.85	.75	.88	.81	.84	*Value Line*		Relative P/E Ratio	**.90**
6.2%	6.7%	5.3%	6.6%	6.1%	4.3%	3.9%	4.1%	3.4%	4.2%	5.5%	4.9%	5.0%	4.6%	4.2%	3.8%	*estimates*		Avg Ann'l Div'd Yield	**4.5%**

CAPITAL STRUCTURE as of 9/30/15
Total Debt $20208 mill. **Due in 5 Yrs** $9052 mill.
LT Debt $17600 mill. **LT Interest** $792 mill.
Incl. $2114 mill. securitized bonds. Incl. $552 mill. capitalized leases.
(LT interest earned: 4.0x)
Leases, Uncapitalized Annual rentals $293 mill.
Pension Assets-12/14 $4968 mill. **Oblig.** $5225 mill.
Pfd Stock None

Common Stock 490,817,402 shs. as of 10/22/15
MARKET CAP: $27 billion (Large Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
12111	12622	13380	14440	13489	14427	15116	14945	15357	17020	**16700**	**17000**	Revenues ($mill)	**18850**
1036.0	1131.0	1147.0	1208.0	1365.0	1248.0	1513.0	1443.0	1549.0	1634.0	**1730**	**1745**	Net Profit ($mill)	**2020**
29.3%	33.0%	31.1%	31.3%	29.7%	34.8%	31.7%	33.9%	36.2%	37.8%	**36.0%**	**36.0%**	Income Tax Rate	**36.0%**
5.4%	9.9%	9.8%	9.9%	10.9%	10.4%	10.6%	11.2%	7.3%	9.0%	**10.0%**	**9.0%**	AFUDC % to Net Profit	**8.0%**
54.8%	56.7%	58.3%	59.1%	54.4%	53.1%	50.7%	50.6%	51.1%	49.0%	**50.0%**	**49.5%**	Long-Term Debt Ratio	**49.0%**
44.9%	43.0%	41.4%	40.7%	45.4%	46.7%	49.3%	49.4%	48.9%	51.0%	**50.0%**	**50.5%**	Common Equity Ratio	**51.0%**
20222	21902	24342	26290	28958	29184	29747	30823	32913	33001	**35400**	**36675**	Total Capital ($mill)	**41500**
24284	26781	29870	32987	34344	35674	36971	38763	40997	44117	**46725**	**49600**	Net Plant ($mill)	**54900**
6.6%	6.7%	6.3%	6.2%	6.2%	5.7%	6.6%	6.1%	6.0%	6.3%	**6.0%**	**6.0%**	Return on Total Cap'l	**6.0%**
11.3%	11.9%	11.3%	11.2%	10.3%	9.1%	10.3%	9.5%	9.6%	9.7%	**10.0%**	**9.5%**	Return on Shr. Equity	**9.5%**
11.3%	12.0%	11.4%	11.3%	10.4%	9.1%	10.3%	9.5%	9.6%	9.7%	**10.5%**	**10.0%**	Return on Com Equity E	**10.0%**
5.2%	5.7%	5.1%	5.1%	4.6%	3.1%	4.2%	3.5%	3.7%	3.8%	**4.5%**	**4.0%**	Retained to Com Eq	**4.0%**
54%	53%	55%	55%	56%	66%	60%	63%	62%	61%	**61%**	**64%**	All Div'ds to Net Prof	**65%**

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-2.1	-1.5	+1.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.3	+.4	+.3
Fixed Charge Cov. (%)	280	326	348

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-1.5%	--	2.5%
"Cash Flow"	1.5%	1.5%	4.5%
Earnings	1.5%	1.5%	5.0%
Dividends	.5%	4.0%	5.0%
Book Value	4.5%	4.5%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	3625	3551	4156	3613	14945
2013	3826	3582	4176	3773	15357
2014	4648	4044	4302	4026	17020
2015	4568	3839	4432	**3861**	**16700**
2016	**4450**	**4050**	**4450**	**4050**	**17000**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.80	.75	1.00	.43	2.98
2013	.75	.73	1.10	.60	3.18
2014	1.15	.80	1.01	.39	3.34
2015	1.28	.88	1.06	**.48**	**3.70**
2016	**1.15**	**.85**	**1.20**	**.50**	**3.70**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.46	.46	.46	.47	1.85
2012	.47	.47	.47	.47	1.88
2013	.47	.49	.49	.50	1.95
2014	.50	.50	.50	.53	2.03
2015	.53	.53	.53	.56	

BUSINESS: American Electric Power Company, Inc. (AEP), through 10 operating utilities, serves 5.4 mill. customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, & West Virginia. Electric rev. breakdown: residential, 40%; commercial, 23%; industrial, 19%; wholesale, 15%; other, 3%. Sold 50% stake in Yorkshire Holdings (British utility) '01; SEEBOARD (British utility) '02; Houston Pipeline '05; commercial barge operation in '15. Generating sources not available. Fuel costs: 36% of revs. '14 reported deprec. rates (utility): 1.4%-8.6%. Has 18,500 employees. Chairman, President & CEO: Nicholas K. Akins. Inc.: NY. Address: 1 Riverside Plaza, Columbus, OH 43215-2373. Tel.: 614-716-1000. Internet: www.aep.com.

American Electric Power is trying to reach a settlement in Ohio about its proposed purchased-power agreement. In recent years, the company has been moving away from the nonregulated side of the business in favor of its regulated utilities. Low capacity prices have hurt the profitability of AEP's nonregulated generating assets. So, the company proposed a purchased-power agreement between some nonregulated generating assets and its utilities in Ohio. The outcome of this matter might well be determined in early 2016. A sale or spinoff of these assets is possible if a settlement is not reached. Note that another company in the state reached a settlement with the commission's staff on a similar proposal, but still faces some opposition—as does AEP.

We have raised our 2015 and 2016 earnings estimates slightly. We lifted our 2015 estimate by $0.10 a share and our 2016 forecast by $0.05 a share. Our $3.70-a-share estimate each year is within AEP's guidance of $3.67-$3.77 and $3.60-$3.80, respectively. The utilities are generally faring well, and are benefiting from rate relief. Increased investment in electric transmission is another plus for AEP. This is outweighing the aforementioned disadvantage of low capacity prices.

Public Service of Oklahoma has a rate case pending. The utility filed for a tariff hike of $172 million, based on a return of 10.5% on a common-equity ratio of 48%. New rates should take effect at the start of 2016.

The board of directors raised the dividend in the fourth quarter. The increase was $0.03 a share (5.7%) quarterly. AEP is targeting a payout ratio of 60%-70%.

The company sold its commercial barge operation. This business earned $0.03 a share in the first three quarters of 2015, which is now included in discontinued operations. The sale raised $400 million in cash, which AEP will use for its regulated utilities. The company hasn't stated whether it will book a gain or loss on the sale.

This stock's valuation is about average for a utility. The dividend yield and total return potential to 2018-2020 are close to the industry averages.

Paul E. Debbas, CFA *December 18, 2015*

(A) Diluted EPS. Excl. nonrec. gains (losses): '02, ($3.86); '03, ($1.92); '04, 24¢; '05, (62¢); '06, (20¢); '07, (20¢); '08, 40¢; '10, (7¢); '11, 89¢; '12, (38¢); '13, (14¢); discont. ops.: '02, (57¢); '03, (32¢); '04, 15¢; '05, 7¢; '06, 2¢; '08, 3¢; '15, 4¢. '14 EPS don't add due to rounding. Next egs. report due late Jan. (B) Div'ds historic. paid early Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '14: $17.67/sh. (D) In mill. (E) Rate base: various. Rates all'd on com. eq.: 9.65%-10.9%; earn. on avg. com. eq., '14: 9.9%. Reg. Clim.: Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	90

EL PASO ELECTRIC NYSE-EE

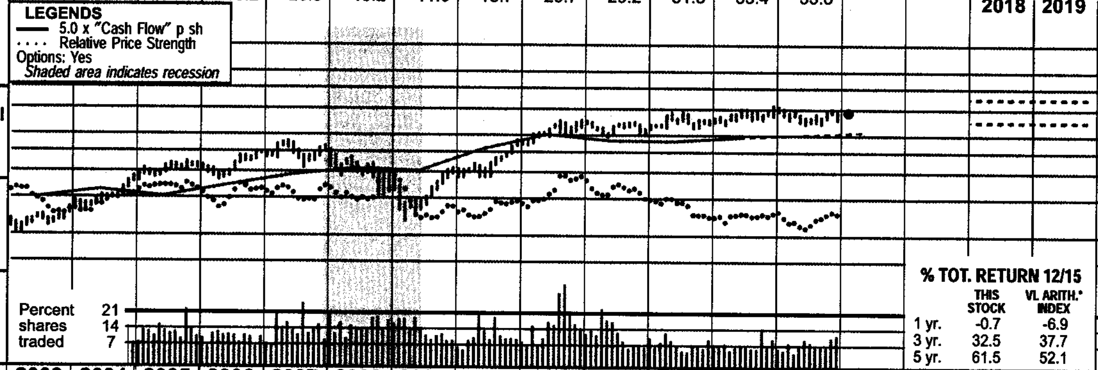
RECENT PRICE 38.70 | P/E RATIO 18.1 (Trailing: 18.3 / Median: 15.0) | RELATIVE P/E RATIO 1.10 | DIV'D YLD 3.2% | VALUE LINE

TIMELINESS 3 Raised 11/13/15
SAFETY 2 Raised 5/11/07
TECHNICAL 3 Lowered 1/1/16
BETA .75 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	19.1	22.4	25.0	28.2	25.5	21.1	28.7	35.7	35.3	39.1	42.2	41.3
Low:	13.1	17.8	18.2	20.8	15.2	11.6	18.7	26.7	29.2	31.8	33.4	33.8

Target Price Range 2018 | 2019 | 2020

LEGENDS
— 5.0 x "Cash Flow" p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+15%)	7%
Low	35	(-10%)	1%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	5	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	88	76	78
to Sell	74	71	63
Hld's(000)	38975	39499	39588

Percent shares traded 21 14 7

% TOT. RETURN 12/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-0.7	-6.9
3 yr.	32.5	37.7
5 yr.	61.5	52.1

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
9.96	13.70	15.40	13.91	13.97	14.95	16.70	17.75	19.43	23.15	18.85	20.61	22.97	21.26	22.11	22.74	21.00	22.15	Revenues per sh	26.75
2.79	3.21	3.43	2.99	3.00	3.27	3.05	3.44	3.86	4.16	4.07	5.15	6.05	5.66	5.65	5.87	6.05	6.25	"Cash Flow" per sh	8.00
.86	1.09	1.27	.57	.64	.69	.76	1.27	1.63	1.73	1.50	2.07	2.48	2.26	2.20	2.27	2.05	2.10	Earnings per sh A	2.75
--	--	--	--	--	--	--	--	--	--	--	--	.66	.97	1.05	1.11	1.17	1.23	Div'd Decl'd per sh B	1.40
1.28	1.70	1.85	1.75	2.03	1.94	2.28	2.73	4.63	5.36	5.95	5.27	5.90	6.70	7.18	8.50	7.90	7.75	Cap'l Spending per sh	7.25
7.36	8.05	9.01	9.20	10.51	11.23	11.56	12.60	14.76	15.47	16.45	19.04	19.03	20.57	23.44	24.39	25.20	26.00	Book Value per sh C	29.50
57.26	51.20	49.99	49.61	47.56	47.40	48.14	46.00	45.15	44.88	43.92	42.57	39.96	40.11	40.27	40.36	40.50	40.65	Common Shs Outst'g D	41.10
9.9	10.6	11.0	23.0	18.3	22.0	26.7	16.9	15.3	11.9	10.8	10.7	12.6	14.5	15.9	16.4	18.1		Avg Ann'l P/E Ratio	14.5
.56	.69	.56	1.26	1.04	1.16	1.42	.91	.81	.72	.72	.68	.79	.92	.89	.86	.90		Relative P/E Ratio	.90
--	--	--	--	--	--	--	--	--	--	--	--	2.1%	3.0%	3.0%	3.0%	3.1%		Avg Ann'l Div'd Yield	3.5%

CAPITAL STRUCTURE as of 9/30/15
Total Debt $1253.0 mill. **Due in 5 Yrs** $201.9 mill.
LT Debt $1134.3 mill. **LT Interest** $68.2 mill.
(LT interest earned: 2.5x)

Leases, Uncapitalized Annual rentals $1.4 mill.
Pension Assets-12/14 $272.9 mill.
Oblig. $341.1 mill.

Pfd Stock None

Common Stock 40,426,668 shs.
as of 10/31/15

MARKET CAP: $1.6 billion (Mid Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
803.9	816.5	877.4	1038.9	828.0	877.3	918.0	852.9	890.4	917.5	850	900	Revenues ($mill)	1100
36.6	61.4	74.8	77.6	66.9	90.3	103.5	90.8	88.6	91.4	85.0	85.0	Net Profit ($mill)	115
33.7%	29.8%	31.6%	32.8%	33.1%	36.1%	34.2%	34.1%	33.0%	31.0%	30.0%	31.0%	Income Tax Rate	31.0%
15.8%	8.0%	15.9%	20.4%	24.3%	22.1%	17.6%	22.4%	24.1%	30.8%	24.0%	24.0%	AFUDC % to Net Profit	13.0%
52.3%	51.5%	49.6%	53.8%	52.7%	51.2%	51.8%	54.8%	51.4%	53.5%	52.5%	55.0%	Long-Term Debt Ratio	55.5%
47.7%	48.5%	50.4%	46.2%	47.3%	48.8%	48.2%	45.2%	48.6%	46.5%	47.5%	45.0%	Common Equity Ratio	44.5%
1167.5	1195.8	1321.6	1503.9	1527.7	1660.1	1576.7	1824.5	1943.5	2118.4	2155	2340	Total Capital ($mill)	2725
1291.7	1332.2	1450.6	1595.6	1756.0	1865.8	1947.1	2102.3	2257.5	2488.4	2645	2790	Net Plant ($mill)	3050
4.9%	6.6%	7.1%	6.7%	6.0%	7.0%	8.3%	6.5%	6.1%	5.7%	5.5%	5.0%	Return on Total Cap'l	6.0%
6.6%	10.6%	11.2%	11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	9.3%	8.0%	8.0%	Return on Shr. Equity	9.5%
6.6%	10.6%	11.2%	11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	9.3%	8.0%	8.0%	Return on Com Equity E	9.5%
6.6%	10.6%	11.2%	11.2%	9.3%	11.1%	10.0%	6.3%	4.9%	4.8%	3.5%	3.5%	Retained to Com Eq	5.0%
--	--	--	--	--	--	26%	43%	47%	49%	56%	59%	All Div'ds to Net Prof	49%

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	+.7	+.4	-1.6
Avg. Indust. Use (MWH)	21659	21908	21505
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	1765	1852	1879
Peak Load, Summer (Mw)	1688	1750	1766
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.5	+1.3	+1.3
Fixed Charge Cov. (%)	302	280	251

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	4.5%	1.5%	3.5%
"Cash Flow"	6.5%	7.5%	5.5%
Earnings	13.5%	6.5%	3.5%
Dividends	--	--	5.0%
Book Value	8.5%	8.0%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	168.6	228.3	267.2	188.8	852.9
2013	177.3	240.1	282.7	190.3	890.4
2014	185.5	251.8	283.6	196.6	917.5
2015	163.7	219.5	289.7	177.1	850
2016	175	240	300	185	900

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.08	.77	1.29	.12	2.26
2013	.19	.72	1.26	.03	2.20
2014	.11	.75	1.30	.10	2.27
2015	.09	.52	1.40	.04	2.05
2016	.05	.65	1.25	.15	2.10

Cal-endar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.22	.25	.25	.25	.97
2013	.25	.265	.265	.265	1.05
2014	.265	.28	.28	.28	1.11
2015	.28	.295	.295	.295	1.17
2016					

BUSINESS: El Paso Electric Company (EPE) provides electric service to 405,000 customers in an area of approximately 10,000 square miles in the Rio Grande valley in western Texas (68% of revenues) and southern New Mexico (19% of revenues), including El Paso, Texas and Las Cruces, New Mexico. Wholesale is 13% of revenues. Electric revenue breakdown by customer class not available. Generating sources: nuclear, 47%; gas, 35%; coal, 5%; purchased, 13%. Fuel costs: 34% of revenues. '14 reported depreciation rate: 2.6%. Has about 1,000 employees. Chairman: Charles A. Yamarone. President & CEO: Mary Kipp. Incorporated: Texas. Address: Stanton Tower, 100 North Stanton, El Paso, Texas 79901. Tel.: 915-543-5711. Internet: www.epelectric.com.

El Paso Electric Company has rate applications pending in Texas and New Mexico. The utility wants to place capital expenditures into the rate base, including its spending on the first two units (88 megawatts each) of a four-unit gas-fired generating station. In Texas, El Paso Electric is seeking a rate hike of $70.5 million, based on a return of 10.1% on a common-equity ratio of 49.52%. The staff of the Texas commission is recommending an increase of $54.3 million, based on a 9.5% ROE, and the city of El Paso is proposing a hike of $23.5 million, based on a 9.1% ROE. In New Mexico, El Paso Electric is asking for $6.4 million, based on a return of 9.95% on a common-equity ratio of 49.29%. The commission's staff is recommending a $3.2 million raise, based on a 9.22% ROE. Although settlements cannot be ruled out, it appears as if each case will be fully litigated, with orders being issued early in the second quarter of 2016.

We have adjusted our earnings estimates for 2015 and 2016. The first two units of the aforementioned generating plant are in service, but are not yet in the rate base. Thus, El Paso Electric is incurring costs (such as depreciation) that are not being recovered. This results in regulatory lag for the utility. We overestimated the effects of regulatory lag in the third quarter of 2015, but underestimated them in the fourth quarter of 2015 and first period of 2016. Because third-quarter profits (aided by favorable weather patterns) exceeded our expectation, we have raised our full-year estimate by $0.10 a share, to $2.05. Our revised estimate is within the company's targeted range of $1.95-$2.10 a share. On the other hand, we have cut our 2016 forecast by $0.10 a share due to our lowered expectation for the March period.

Finances are sound. The fixed-charge coverage, common-equity ratio, and return on equity are comparable with the norms for the electric utility industry.

The dividend yield of El Paso Electric stock is low, by utility standards. This reflects, in part, the company's good dividend growth prospects through 2018-2020. However, with the recent quotation within our 3- to 5-year Target Price Range (like that of many utility issues), total return potential is lackluster.

Paul E. Debbas, CFA *January 29, 2016*

(A) Diluted earnings. Excl. nonrecurring gains (losses): '99, (38¢); '01, (4¢); '03, 81¢; '04, 4¢; '05, (2¢); '06, 13¢; '10, 24¢. '14 earnings don't add to full-year total due to rounding. Next earnings report due late Feb. (B) Initial dividend declared 4/11; payment dates in late March, June, Sept., and Dec. (C) Incl. deferred charges. In '14: $112.1 mill., $2.78/sh. (D) In millions. (E) Rate allowed on common equity in TX in '12: none specified; in NM in '10: none specified; earned on average common equity, '14: 9.5%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	65
Earnings Predictability	85

EMPIRE DISTRICT NYSE-EDE

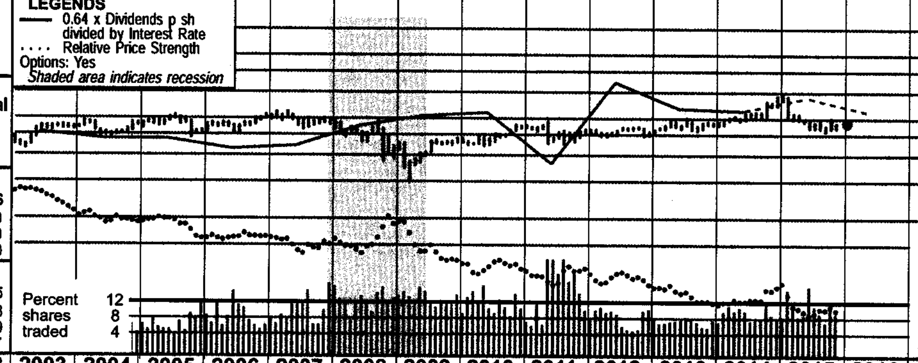
RECENT PRICE 22.81 | P/E RATIO 15.7 (Trailing: 17.2 Median: 16.0) | RELATIVE P/E RATIO 0.89 | DIV'D YLD 4.6% | VALUE LINE

TIMELINESS 4 Raised 11/20/15
SAFETY 2 Raised 3/23/12
TECHNICAL 4 Lowered 12/4/15
BETA .70 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	23.5	25.0	25.1	26.1	23.5	19.4	22.5	23.3	22.0	24.3	31.2	31.5
Low:	19.5	19.3	20.3	21.1	14.9	11.9	17.6	18.0	19.5	20.6	22.0	20.7

Target Price Range 2018 | 2019 | 2020

LEGENDS
— 0.64 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	25	(+10%)	7%
Low	20	(-10%)	2%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	1	0	0	0	0	0	0	0

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	70	65	68
to Sell	65	65	49
Hld's(000)	20494	20421	20727

Percent shares traded 12 / 8 / 4

% TOT. RETURN 11/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-14.1	-2.0
3 yr.	29.8	48.1
5 yr.	30.5	71.2

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
13.94	14.78	13.37	13.56	13.03	12.67	14.80	13.67	14.59	15.25	13.04	13.02	13.74	13.11	13.81	15.00	*13.85*	*14.00*	Revenues per sh	*16.00*
2.89	3.12	2.19	2.43	2.48	2.22	2.45	2.75	2.69	2.91	2.72	2.85	3.21	2.99	3.14	3.45	*3.50*	*3.60*	"Cash Flow" per sh	*4.25*
1.13	1.35	.59	1.19	1.29	.86	.92	1.41	1.09	1.17	1.18	1.17	1.31	1.32	1.48	1.55	*1.35*	*1.45*	Earnings per sh A	*1.75*
1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	.64	1.00	1.01	1.03	*1.04*	*1.04*	Div'd Decl'd per sh B ■ †	*1.15*
4.14	7.61	4.02	3.43	2.65	1.64	2.83	3.97	5.46	6.28	4.07	2.63	2.44	3.22	3.60	4.91	*4.05*	*2.75*	Cap'l Spending per sh	*3.50*
13.48	13.65	13.58	14.59	15.17	14.76	15.08	15.49	16.04	15.56	15.75	15.82	16.53	16.90	17.43	18.02	*18.30*	*18.80*	Book Value per sh C	*20.50*
17.37	17.60	19.76	22.57	24.98	25.70	26.08	30.25	33.61	33.98	38.11	41.58	41.98	42.48	43.04	43.48	*44.00*	*46.00*	Common Shs Outst'g D	*47.50*
21.7	17.7	33.9	16.2	15.8	24.8	24.5	15.9	21.7	17.3	14.3	16.8	15.8	15.8	15.0	16.2	*Bold figures are*		Avg Ann'l P/E Ratio	*12.5*
1.24	1.15	1.74	.88	.90	1.31	1.30	.86	1.15	1.04	.95	1.07	.99	1.01	.84	.85	*Value Line*		Relative P/E Ratio	*.80*
5.2%	5.4%	6.4%	6.6%	6.3%	6.0%	5.7%	5.7%	5.4%	6.3%	7.6%	6.5%	3.1%	4.8%	4.5%	4.1%	*estimates*		Avg Ann'l Div'd Yield	*5.0%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $879.6 mill. Due in 5 Yrs $213.6 mill.
LT Debt $863.0 mill. LT Interest $43.9 mill.
Incl. $3.7 mill. capitalized leases.
(LT interest earned: 3.0x)
Leases, Uncapitalized Annual rentals $.7 mill.
Pension Assets-12/14 $192.7 mill. Oblig. $251.9 mill.
Pfd Stock None

Common Stock 43,787,249 shs. as of 10/30/15

MARKET CAP: $1.0 billion (Mid Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
386.2	413.5	490.2	518.2	497.2	541.3	576.9	557.1	594.3	652.3	*610*	*645*	Revenues ($mill)	*765*
23.8	39.9	33.2	39.7	41.3	47.4	55.0	55.7	63.4	67.1	*55.0*	*65.0*	Net Profit ($mill)	*85.0*
33.4%	35.4%	30.3%	32.5%	32.5%	39.2%	38.4%	38.0%	37.1%	36.9%	*37.5%*	*38.0%*	Income Tax Rate	*37.5%*
2.4%	10.7%	23.1%	31.5%	34.2%	21.5%	.9%	3.5%	9.4%	14.8%	*10.0%*	*3.0%*	AFUDC % to Net Profit	*6.0%*
51.0%	49.7%	50.1%	53.6%	51.6%	51.3%	49.9%	49.1%	49.8%	50.6%	*51.0%*	*52.0%*	Long-Term Debt Ratio	*50.0%*
49.0%	50.3%	49.9%	46.4%	48.4%	48.7%	50.1%	50.9%	50.2%	49.4%	*49.0%*	*48.0%*	Common Equity Ratio	*50.0%*
803.3	931.0	1081.1	1140.4	1240.3	1350.7	1386.2	1409.4	1493.6	1586.5	*1645*	*1805*	Total Capital ($mill)	*1925*
896.0	1031.0	1178.9	1342.8	1459.0	1519.1	1563.7	1657.6	1751.9	1910.3	*1995*	*2020*	Net Plant ($mill)	*2150*
4.7%	5.9%	4.7%	5.2%	5.2%	5.1%	5.5%	5.4%	5.6%	5.5%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.5%*
6.0%	8.5%	6.2%	7.5%	6.9%	7.2%	7.9%	7.8%	8.5%	8.6%	*7.5%*	*7.5%*	Return on Shr. Equity	*8.5%*
6.0%	8.5%	6.2%	7.5%	6.9%	7.2%	7.9%	7.8%	8.5%	8.6%	*7.5%*	*7.5%*	Return on Com Equity E	*8.5%*
NMF	.8%	NMF	NMF	NMF	NMF	4.1%	1.9%	2.7%	2.9%	*2.0%*	*2.0%*	Retained to Com Eq	*3.0%*
NMF	90%	117%	109%	109%	110%	49%	76%	68%	66%	*76%*	*71%*	All Div'ds to Net Prof	*64%*

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-3.2	+1.3	+1.3
Avg. Industrial Use (MWH)	2913	2943	2981
Avg. Industrial Rev/KWH (¢)	7.66	7.93	8.21
Capacity at Peak (Mw)	1391	1377	1326
Peak Load, Summer (Mw)	1142	1080	1162
Annual Load Factor (%)	52.2	56.2	52.8
% Change Customers (avg.)	+.6	+.5	+.3
Fixed Charge Cov. (%)	314	331	334

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	.5%	-.5%	*2.5%*
"Cash Flow"	3.0%	3.0%	*5.0%*
Earnings	2.5%	5.0%	*3.0%*
Dividends	-2.5%	-4.5%	*2.0%*
Book Value	1.5%	2.0%	*2.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	137.2	131.6	159.2	129.1	557.1
2013	151.1	136.6	157.5	149.1	594.3
2014	179.7	149.8	171.5	151.3	652.3
2015	164.5	134.5	169.7	*141.3*	*610*
2016	*180*	*145*	*170*	*150*	*645*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.23	.25	.60	.23	1.32
2013	.30	.27	.56	.35	1.48
2014	.48	.26	.55	.26	1.55
2015	.34	.15	.58	*.28*	*1.35*
2016	*.34*	*.25*	*.57*	*.29*	*1.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.32	.32	--	--	.64
2012	.25	.25	.25	.25	1.00
2013	.25	.25	.25	.255	1.01
2014	.255	.255	.255	.26	1.03
2015	.26	.26	.26	.26	

BUSINESS: The Empire District Electric Company supplies electricity to 169,000 customers in a 10,000 sq. mi. area in southwestern Missouri (90% of retail elec. revs.), Kansas (5%), Oklahoma (3%), & Arkansas (2%). Acquired Missouri Gas (44,000 customers) 6/06. Supplies water service (4,000 customers) and has a small fiber-optics operation. Elec. rev. breakdown: residential, 45%; commercial, 32%; industrial, 16%; other, 7%. Generating sources: coal, 47%; gas, 27%; hydro, 1%; purch., 25%. Fuel costs: 37% of revenues. '14 reported depr. rate: 3.0%. Has about 750 employees. Chairman: D. Randy Laney. President & CEO: Bradley P. Beecher. Inc.: KS. Address: 602 S. Joplin Ave., P.O. Box 127, Joplin, MO 64802-0127. Tel.: 417-625-5100. Internet: www.empiredistrict.com.

Empire District Electric Company has filed another rate case in Missouri. The utility received a $17.1 million (3.9%) tariff hike in July, which enabled it to place an environmental project in the rate base. Now, Empire District Electric is seeking to place another project, a $165 million-$175 million upgrade to a gas-fired unit, which will add 100 megawatts of capacity, in rates. In addition, the utility earned a return on equity of just 7.2% in the 12-month period that ended on September 30th. So, the company is asking the Missouri regulators for a $33.4 million (7.3%) rate increase, based on a 9.9% return on a 49% common-equity ratio. New tariffs are expected to go into effect in September of 2016. A corresponding filing will also be made in Oklahoma, which represents a much smaller proportion of the utility's business than does Missouri. New rates should take effect 30 days after the order is implemented in Missouri.

Regulatory lag affected Empire District Electric's earnings this year, and will do so again in 2016. The assets that the utility is adding were and are being completed several months before the rate hikes took and will take effect. Thus, during that span, some costs (such as depreciation) are not being recovered in rates. This is an ongoing problem for utilities in Missouri, and helps explain the low ROEs that Empire District Electric has earned for a long time. Our 2015 earnings estimate of $1.35 a share, which is within the company's guidance of $1.30-$1.45, would produce a 13% decline from the 2014 tally. We forecast just a partial profit recovery in 2016.

The board of directors did not raise the dividend in the fourth quarter. This is in contrast to the two previous years. The board was concerned that the payout ratio is at the high end of a reasonable range for most utilities.

Untimely Empire District Electric stock has performed poorly this year. Its price has declined 23% since the start of 2015. We attribute this to a lessening of takeover speculation, not a worsening of the company's prospects. The stock's dividend yield is above average for a utility, but 3- to 5-year total return potential is unimpressive.

Paul E. Debbas, CFA — *December 18, 2015*

(A) Diluted earnings. Excl. loss from discontinued operations: '06, 2¢. '12 EPS don't add due to rounding. Next earnings report due early Feb. (B) Div'ds historically paid in mid-Mar., June, Sept. and Dec. Div'ds suspended 3Q '11, reinstated 1Q '12. ■ Div'd reinvestment plan avail. (3% discount). † Shareholder investment plan avail. (C) Incl. intangibles. In '14: $5.93/sh. (D) In mill. (E) Rate base: Deprec. orig. cost. Rate allowed on com. eq. in MO in '15: none specified; earned on avg. com. eq., '14: 8.7%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	25
Earnings Predictability	85

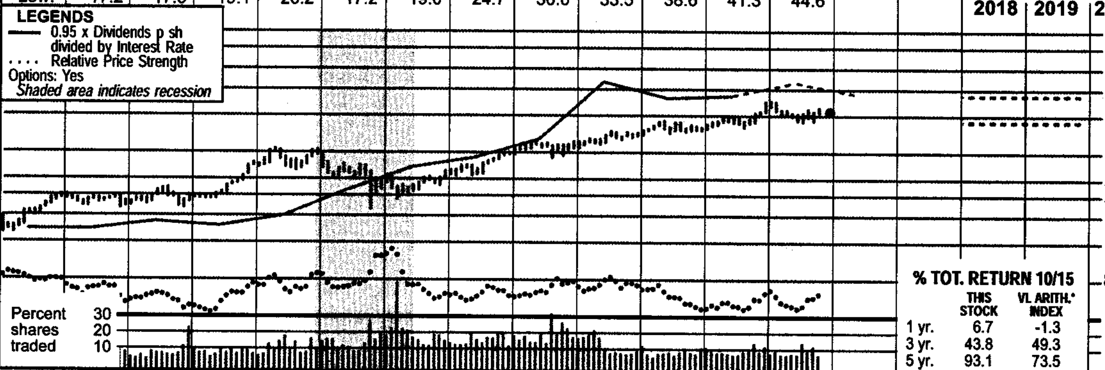
EVERSOURCE ENERGY NYSE-ES

RECENT PRICE	50.37	P/E RATIO	17.7 (Trailing: 17.5 / Median: 17.0)	RELATIVE P/E RATIO	0.99	DIV'D YLD	3.5%	VALUE LINE

TIMELINESS 3 Lowered 8/14/15
SAFETY 1 Raised 5/22/15
TECHNICAL 1 Raised 11/20/15
BETA .75 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	20.3	22.0	28.9	33.6	31.6	26.5	32.2	36.5	40.9	45.7	56.7	56.8
Low:	17.2	17.3	19.1	26.2	17.2	19.0	24.7	30.0	33.5	38.6	41.3	44.6

Target Price Range 2018 | 2019 | 2020



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+20%)	8%
Low	45	(-10%)	2%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	1
to Sell	0	0	0	2	0	1	2	0	2

Institutional Decisions

	4Q2014	1Q2015	2Q2015
to Buy	233	203	236
to Sell	211	255	206
Hld's(000)	223425	223824	226206

% TOT. RETURN 10/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	6.7	-1.3
3 yr.	43.8	49.3
5 yr.	93.1	73.5

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
33.91	40.86	52.82	40.89	47.53	51.82	41.85	44.64	37.27	37.22	30.97	27.76	25.21	19.98	23.16	24.42	*25.80*	*26.00*	Revenues per sh	*28.00*
5.68	3.39	10.48	6.32	5.80	5.00	5.46	3.69	4.82	6.16	4.96	5.68	4.88	4.03	5.22	4.56	*5.20*	*5.55*	"Cash Flow" per sh	*6.75*
d1.14	d.20	1.37	1.08	1.24	.91	.98	.82	1.59	1.86	1.91	2.10	2.22	1.89	2.49	2.58	*2.80*	*3.00*	Earnings per sh A	*3.75*
.10	.40	.45	.53	.58	.63	.68	.73	.78	.83	.95	1.03	1.10	1.32	1.47	1.57	*1.67*	*1.78*	Div'd Decl'd per sh B ■	*2.10*
2.50	2.88	3.40	3.86	4.31	4.85	5.89	5.49	7.14	8.06	5.17	5.41	6.08	4.69	4.62	5.06	*5.80*	*6.65*	Cap'l Spending per sh	*6.25*
15.80	15.43	16.27	17.33	17.73	17.80	18.46	18.14	18.65	19.38	20.37	21.60	22.65	29.41	30.49	31.47	*32.55*	*33.75*	Book Value per sh C	*38.00*
131.87	143.82	130.13	127.56	127.70	129.03	131.59	154.23	156.22	155.83	175.62	176.45	177.16	314.05	315.27	316.98	*318.00*	*319.00*	Common Shs Outst'g D	*322.00*
--	--	14.1	16.1	13.4	20.8	19.8	27.1	18.7	13.7	12.0	13.4	15.4	19.9	16.9	17.9	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
--	--	.72	.88	.76	1.10	1.05	1.46	.99	.82	.80	.85	.97	1.27	.95	.95	*Value Line*		Relative P/E Ratio	*.90*
.6%	1.9%	2.3%	3.0%	3.5%	3.3%	3.5%	3.3%	2.6%	3.2%	4.2%	3.6%	3.2%	3.5%	3.5%	3.4%	*estimates*		Avg Ann'l Div'd Yield	*4.0%*

CAPITAL STRUCTURE as of 6/30/15
Total Debt $9922.2 mill. **Due in 5 Yrs** $3763.9 mill.
LT Debt $8689.6 mill. **LT Interest** $376.3 mill.
(LT interest earned: 4.7x)

Leases, Uncapitalized Annual rentals $20.1 mill.
Pension Assets-12/14 $4126.5 mill.
Oblig. $5486.2 mill.
Pfd Stock $155.6 mill. **Pfd Div'd** $7.6 mill.
Incl. 2,324,000 shs $1.90-$3.28 rates ($50 par) not subject to mandatory redemption.
Common Stock 317,173,164 shs.
as of 7/31/15
MARKET CAP: $16 billion (Large Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
5507.3	6884.4	5822.2	5800.1	5439.4	4898.2	4465.7	6273.8	7301.2	7741.9	*8200*	*8300*	Revenues ($mill)	*9000*
128.5	126.2	251.5	296.2	335.6	377.8	400.3	533.0	793.7	827.1	*905*	*970*	Net Profit ($mill)	*1200*
30.8%	--	30.3%	29.7%	34.9%	36.6%	29.9%	34.0%	35.0%	36.2%	*37.5%*	*36.5%*	Income Tax Rate	*36.5%*
17.4%	21.5%	13.9%	15.8%	4.6%	7.1%	8.6%	2.3%	1.4%	2.4%	*4.0%*	*4.0%*	AFUDC % to Net Profit	*3.0%*
63.2%	58.7%	59.2%	60.4%	57.2%	55.1%	53.4%	43.7%	44.3%	45.9%	*46.5%*	*46.5%*	Long-Term Debt Ratio	*46.5%*
35.1%	39.7%	39.2%	38.1%	41.5%	43.6%	45.3%	55.4%	54.8%	53.2%	*53.0%*	*53.0%*	Common Equity Ratio	*53.0%*
6923.2	7052.0	7431.1	7926.2	8629.5	8741.8	8856.0	16675	17544	18738	*19575*	*20375*	Total Capital ($mill)	*23100*
6417.2	6242.2	7229.9	8207.9	8840.0	9567.7	10403	16605	17576	18647	*19900*	*21350*	Net Plant ($mill)	*25500*
3.5%	2.9%	5.0%	5.4%	5.4%	5.8%	5.9%	4.2%	5.5%	5.3%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
5.0%	4.3%	8.3%	9.4%	9.1%	9.6%	9.7%	5.7%	8.1%	8.2%	*8.5%*	*9.0%*	Return on Shr. Equity	*9.5%*
5.1%	4.3%	8.4%	9.6%	9.2%	9.8%	9.8%	5.7%	8.2%	8.2%	*8.5%*	*9.0%*	Return on Com Equity E	*9.5%*
1.5%	.3%	4.3%	5.3%	4.7%	5.0%	5.0%	1.6%	3.4%	3.5%	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
72%	94%	50%	45%	50%	49%	50%	72%	59%	58%	*59%*	*59%*	All Div'ds to Net Prof	*57%*

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	+47.0	+1.0	-1.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+59.8	NA	NA
Fixed Charge Cov. (%)	320	427	426

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-7.0%	-8.5%	*3.5%*
"Cash Flow"	-2.0%	-3.0%	*6.5%*
Earnings	8.0%	5.5%	*8.5%*
Dividends	9.5%	11.5%	*6.5%*
Book Value	5.5%	9.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	1099	1628	1861	1684	6273.8
2013	1995	1635	1892	1777	7301.2
2014	2290	1677	1892	1881	7741.9
2015	2513	1817	1933	*1937*	*8200*
2016	*2500*	*1850*	*2000*	*1950*	*8300*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.56	.15	.66	.55	1.89
2013	.72	.54	.66	.56	2.49
2014	.74	.40	.74	.69	2.58
2015	.80	.65	.74	*.61*	*2.80*
2016	*.85*	*.65*	*.80*	*.70*	*3.00*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.275	.275	.275	.275	1.10
2012	.294	.343	.343	.343	1.32
2013	.3675	.3675	.3675	.3675	1.47
2014	.3925	.3925	.3925	.3925	1.57
2015	.4175	.4175	.4175		

BUSINESS: Eversource Energy (formerly Northeast Utilities) is the parent of utilities that have 3.1 million electric, 504,000 gas customers. Supplies power to most of Connecticut and gas to part of Connecticut; supplies power to three fourths of New Hampshire's population; supplies power to western Massachusetts and parts of eastern Massachusetts & gas to central & eastern Massachusetts. Acquired NSTAR 4/12. Electric revenue breakdown: residential, 49%; commercial, 38%; industrial, 5%; other, 8%. Fuel costs: 39% of revenues. '14 reported deprec. rates: 2.7%-3.3%. Has 8,200 employees. Chairman, President & CEO: Thomas J. May. Inc.: MA. Address: 300 Cadwell Drive, Springfield, MA 01104. Tel.: 413-785-5871. Internet: www.eversource.com.

Eversource Energy was granted a gas rate increase in Massachusetts. The regulators raised rates by $15.8 million, based on a 9.8% return on a 52.1% common-equity ratio. New tariffs will take effect at the start of 2016.

Rate relief is one reason why earnings are likely to advance significantly this year and next. Eversource is also benefiting from an electric rate hike in Connecticut that took effect in late 2014. Another factor is customer conversions from oil heat to gas heat. The company is reducing expenses, too. Even so, we have lowered our 2015 earnings estimate by $0.10 a share because the tax rate will be higher than we had expected. Our revised profit estimate is at the low end of Eversource's guidance of $2.80-$2.85 a share.

Eversource is proposing to sell its generating assets in New Hampshire. These assets have a book value of $650 million and are earning $0.09-$0.10 a share annually. If approved, the utility would recover its stranded costs by issuing securitized bonds. A decision is expected by yearend.

The company is proposing a grid modernization plan in Massachusetts. Eversource would spend $430 million through 2021. The utility would recover its costs through a tracking mechanism, rather than by filing general rate cases. A ruling from the regulators is expected in 2016.

Eversource is seeking permission to build a transmission line to Canada. When the project was proposed several years ago, it was expected to cost under $1 billion, but the latest estimate is $1.6 billion because of inflation, plus the route has changed and some of the line will be built underground. The goal is for the line to go into service in the first half of 2019.

We expect a dividend increase in the first quarter of 2016. We think the board of directors will raise the annual disbursement by $0.11 a share (6.6%).

Eversource's strong points are reflected in the share price. Although prospects for earnings and dividend growth are solid, the stock's 3- to 5-year total return potential is low. Meanwhile, the dividend yield is a bit below the industry mean.

Paul E. Debbas, CFA *November 20, 2015*

(A) Dil. EPS. Excl. nonrec. gains (losses): '02, 10¢; '03, (32¢); '04, (7¢); '05, ($1.36); '08, (19¢); '10, 9¢. '12 EPS don't add due to chng. in shs., '13 & '14 due to rounding. Next egs. report due early Feb. (B) Div'ds histor. paid late Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. def'd chgs. In '14: $23.89/sh. (D) In mill. (E) Rate all'd on com. eq. in MA: (elec) '11, 9.6%; (gas) '16, 9.8%; in CT: (elec.) '15, 9.02%; (gas) '15, 9.5%; in NH: '10, 9.67%; earn. on avg. com. eq., '14: 8.4%. Reg. Clim.: CT, Below Avg.; NH, Avg.; MA, Above Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	80
Earnings Predictability	85

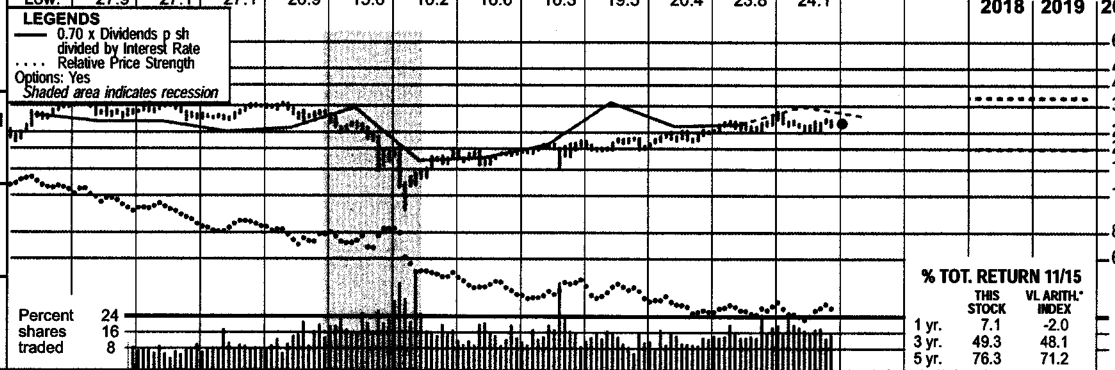
GREAT PLAINS EN'GY NYSE-GXP

RECENT PRICE 26.56 | P/E RATIO 17.1 (Trailing: 19.8 Median: 16.0) | RELATIVE P/E RATIO 0.97 | DIV'D YLD 4.0% | VALUE LINE

TIMELINESS 3 Raised 12/18/15
SAFETY 3 Lowered 12/26/08
TECHNICAL 1 Raised 12/18/15
BETA .85 (1.00 = Market)

High:	35.7	32.8	32.8	33.4	29.3	20.5	19.9	22.1	22.8	24.9	29.5	30.3
Low:	27.9	27.1	27.1	26.9	15.6	10.2	16.6	16.3	19.5	20.4	23.8	24.1

LEGENDS
— 0.70 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2018 | 2019 | 2020

2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+30%)	10%
Low	20	(-25%)	-2%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	9	0	0	0	0	0	0

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	125	122	108
to Sell	148	125	134
Hld's(000)	121848	130044	125340

Percent shares traded 24 16 8

% TOT. RETURN 11/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	7.1	-2.0
3 yr.	49.3	48.1
5 yr.	76.3	71.2

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
14.50	18.02	23.61	26.91	31.04	33.13	34.85	33.30	37.89	14.00	14.51	16.62	17.03	15.05	15.90	16.66	15.85	17.10	Revenues per sh	19.25
3.63	4.63	4.70	4.40	4.69	4.75	4.54	3.86	4.24	3.09	3.27	4.12	3.51	3.45	4.01	4.01	3.95	4.60	"Cash Flow" per sh	6.00
1.26	2.05	1.59	2.04	2.27	2.46	2.18	1.62	1.86	1.16	1.03	1.53	1.25	1.35	1.62	1.57	1.35	1.75	Earnings per sh A	2.00
1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	.83	.83	.84	.86	.88	.94	1.00	1.06	Div'd Decl'd per sh B ■	1.20
2.97	6.67	4.38	1.91	2.19	2.66	4.49	6.05	6.15	8.86	6.49	4.76	3.40	4.01	4.42	5.10	5.20	4.05	Cap'l Spending per sh	3.75
13.97	14.88	12.59	13.58	13.82	15.35	16.37	16.70	18.18	21.39	20.62	21.26	21.74	21.75	22.58	23.26	23.60	24.30	Book Value per sh C	26.75
61.91	61.91	61.91	69.20	69.26	74.37	74.74	80.35	86.23	119.26	135.42	135.71	136.14	153.53	153.87	154.16	154.50	154.75	Common Shs Outst'g D	155.50
20.0	12.4	15.9	11.1	12.2	12.6	14.0	18.3	16.3	20.5	16.0	12.1	16.1	15.5	14.2	16.5	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	13.5
1.14	.81	.81	.61	.70	.67	.75	.99	.87	1.23	1.07	.77	1.01	.99	.80	.87			Relative P/E Ratio	.85
6.6%	6.5%	6.6%	7.3%	6.0%	5.4%	5.5%	5.6%	5.5%	7.0%	5.0%	4.5%	4.1%	4.1%	3.8%	3.6%			Avg Ann'l Div'd Yield	4.6%
						2604.9	2675.3	3267.1	1670.1	1965.0	2255.5	2318.0	2309.9	2446.3	2568.2	2450	2650	Revenues ($mill)	3000
						164.2	127.6	159.2	119.5	135.6	211.7	174.4	199.9	250.2	242.8	215	275	Net Profit ($mill)	315
						18.7%	27.0%	30.7%	34.5%	25.0%	31.7%	32.7%	34.3%	34.0%	32.3%	35.0%	35.0%	Income Tax Rate	35.0%
						2.1%	8.4%	10.6%	46.8%	57.0%	25.7%	3.9%	3.3%	10.4%	12.8%	5.0%	2.0%	AFUDC % to Net Profit	2.0%
						47.5%	30.6%	40.7%	49.7%	53.2%	50.2%	47.8%	44.9%	50.0%	49.0%	51.0%	47.5%	Long-Term Debt Ratio	48.0%
						50.9%	67.5%	57.9%	49.6%	46.2%	49.2%	51.6%	54.4%	49.4%	50.4%	48.5%	52.0%	Common Equity Ratio	51.5%
						2403.3	1988.4	2709.8	5146.2	6044.5	5867.6	5741.2	6135.8	7029.1	7113.1	7525	7255	Total Capital ($mill)	8050
						2765.6	3066.2	3444.5	6081.3	6651.1	6892.3	7053.5	7402.1	7746.4	8279.6	8690	8875	Net Plant ($mill)	9050
						8.2%	7.9%	7.5%	3.5%	3.9%	5.3%	5.0%	5.0%	5.0%	4.7%	4.0%	5.0%	Return on Total Cap'l	5.0%
						13.0%	9.2%	9.9%	4.6%	4.8%	7.2%	5.8%	5.9%	7.1%	6.7%	6.0%	7.0%	Return on Shr. Equity	7.5%
						13.3%	9.4%	10.1%	4.6%	4.8%	7.3%	5.8%	5.9%	7.2%	6.7%	6.0%	7.5%	Return on Com Equity E	7.5%
						3.2%	NMF	.9%	NMF	.9%	3.4%	2.0%	2.2%	3.2%	2.7%	1.5%	3.0%	Retained to Com Eq	3.0%
						76%	104%	91%	NMF	81%	54%	66%	63%	55%	60%	73%	60%	All Div'ds to Net Prof	62%

CAPITAL STRUCTURE as of 9/30/15
Total Debt $4105.7 mill. Due in 5 Yrs $1472.6 mill.
LT Debt $3763.5 mill. LT Interest $188.9 mill.
(LT interest earned: 2.4x)

Leases, Uncapitalized Annual rentals $14.2 mill.
Pension Assets-12/14 $730.0 mill. Oblig. $1186.8 mill.
Pfd Stock $39.0 mill. Pfd Div'd $1.6 mill.
390,000 shs. 3.80% to 4.50% (all $100 par & cum.), callable from $101 to $103.70.
Common Stock 154,369,354 shs. as of 11/2/15
MARKET CAP: $4.1 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-1.8	+.2	+.4
Avg. Indust. Use (MWH)	1443	1424	1455
Avg. Indust. Revs. per KWH (¢)	6.23	6.80	6.79
Capacity at Peak (Mw)	6719	NA	NA
Peak Load, Summer (Mw)	5653	NA	NA
Annual Load Factor (%)	49.6	NA	NA
% Change Customers (avg.)	+.2	+.7	+.9
Fixed Charge Cov. (%)	235	267	261

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-6.5%	-6.5%	3.5%
"Cash Flow"	-2.0%	1.5%	8.0%
Earnings	-4.0%	2.5%	5.0%
Dividends	-6.0%	-8.5%	6.0%
Book Value	4.5%	2.5%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	479.7	603.6	746.2	480.4	2309.9
2013	542.2	600.3	765.0	538.8	2446.3
2014	585.1	648.4	782.5	552.2	2568.2
2015	549.1	609.0	781.4	510.5	2450
2016	600	650	850	550	2650

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	d.07	.41	.95	.03	1.35
2013	.17	.41	.93	.11	1.62
2014	.15	.34	.95	.12	1.57
2015	.12	.28	.82	.13	1.35
2016	.20	.40	1.00	.15	1.75

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.2075	.2075	.2075	.2125	.84
2012	.2125	.2125	.2125	.2175	.86
2013	.2175	.2175	.2175	.23	.88
2014	.23	.23	.23	.245	.94
2015	.245	.245	.245	.2625	

BUSINESS: Great Plains Energy Incorporated is a holding company for Kansas City Power & Light and two other subsidiaries, which supply electricity to 844,000 customers in western Missouri (71% of revenues) and eastern Kansas (29%). Acq'd Aquila 7/08. Sold Strategic Energy (energy-marketing subsidiary) in '08. Electric revenue breakdown: residential, 40%; commercial, 39%; industrial, 9%; other, 12%. Generating sources: coal, 64%; nuclear, 13%; wind, 1%; gas & oil, 1%; purchased, 21%. Fuel costs: 29% of revs. '14 reported deprec. rate (utility): 3.0%. Has 2,900 employees. Chairman: Michael J. Chesser. President & CEO: Terry Bassham. Inc.: Missouri. Address: 1200 Main St., Kansas City, Missouri 64105. Tel.: 816-556-2200. Internet: www.greatplainsenergy.com.

Great Plains Energy's largest utility subsidiary received a rate order in Kansas. Kansas City Power & Light was granted a tariff hike of $48.7 million (9.0%), based on a return of 9.3% on a common-equity ratio of 50.48%. New rates took effect at the start of October. KCP&L also received a rate increase of $89.7 million (11.8%), based on a 9.5% return on a 50.09% common-equity ratio, in mid-September.

There were good and bad aspects to the rate orders. KCP&L received more than 75% of what it requested, and will earn a return on its entire investment in an environmental upgrade to a coal-fired plant. The utility was also granted a fuel-adjustment mechanism in Missouri. (It already had one in Kansas.) However, the company did not get other regulatory mechanisms it sought in Missouri, and is disappointed with the low allowed ROEs. It has appealed these issues to the courts in Missouri and Kansas.

We have cut our 2015 earnings estimate by a nickel a share. Third-quarter profits fell short of our estimate. Management narrowed its share-earnings guidance from $1.35-$1.60 to $1.35-$1.45, and our revised profit estimate is at the low end of this range. In recent years, the company has been earning mediocre ROEs due to the effects of regulatory lag. The rate orders came too late to have much effect on earnings this year, but . . .

We continue to expect a significant profit increase in 2016. The rate orders should help the utility reduce (but won't eliminate) the regulatory lag problem. Our forecast would result in a 30% bottom-line increase over our 2015 estimate. Great Plains Energy will put forth 2016 guidance in its conference call in late February.

The board of directors has raised the dividend. The board boosted the annual disbursement by $0.07 a share (7.1%), effective with the fourth-quarter payment. Great Plains is now targeting a payout ratio in a range of 55%-70%, but wants to narrow this to 60%-70% after 2016.

Great Plains Energy stock has an average dividend yield for a utility. With the recent price near the midpoint of our 3- to 5-year Target Price Range, total return potential is low.

Paul E. Debbas, CFA *December 18, 2015*

(A) Dil. EPS. Excl. nonrec. gains (losses): '00, 49¢; '01, ($2.01); '02, (5¢); '03, 29¢; '04, (7¢); '09, 12¢; gain (losses) on disc. ops.: '03, (13¢); '04, 10¢; '05, (3¢); '08, 35¢. '12 EPS don't add due to change in shs., '14 due to rounding. Next earnings report due late Feb. (B) Div'ds historically paid in mid-Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '14: $7.81/sh. (D) In mill. (E) Rate base: Fair value. Rate all'd on com. eq. in MO in '15: 9.5%; in KS in '15: 9.3%; earned on avg. com. eq., '14: 6.8%. Regulatory Climate: Average.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	5
Earnings Predictability	75

IDACORP, INC. NYSE-IDA

RECENT PRICE	67.59	P/E RATIO	17.8 (Trailing: 17.2 / Median: 14.0)	RELATIVE P/E RATIO	1.09	DIV'D YLD	3.0%	VALUE LINE

TIMELINESS 3 Lowered 5/15/15
SAFETY 2 Raised 8/2/13
TECHNICAL 3 Lowered 12/4/15
BETA .80 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	32.9	32.1	40.2	39.2	35.1	32.8	37.8	42.7	45.7	54.7	70.1	70.5
Low:	25.3	26.2	29.0	30.1	21.9	20.9	30.0	33.9	38.2	43.1	50.2	55.4

Target Price Range 2018 | 2019 | 2020

2018-20 PROJECTIONS

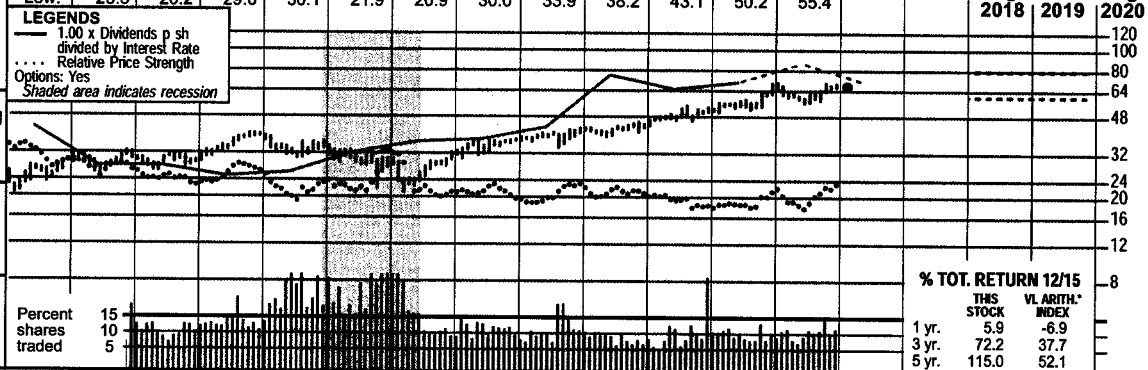
	Price	Gain	Ann'l Total Return
High	80	(+20%)	7%
Low	60	(-10%)	1%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	2	0	0	1	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	2	1	1	1	1	0	1	1	1

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	106	101	106
to Sell	92	100	95
Hld's(000)	37715	37671	67529



% TOT. RETURN 12/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	5.9	-6.9
3 yr.	72.2	37.7
5 yr.	115.0	52.1

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
17.50	27.10	150.10	24.43	20.41	20.00	20.15	21.23	19.51	20.47	21.92	20.97	20.55	21.55	24.81	25.51	*24.95*	*26.05*	Revenues per sh	*27.95*
4.50	5.63	5.63	4.08	3.50	4.12	3.87	4.58	4.11	4.27	5.07	5.23	5.74	5.84	6.21	6.49	*6.45*	*6.70*	"Cash Flow" per sh	*7.50*
2.43	3.50	3.35	1.63	.96	1.90	1.75	2.35	1.86	2.18	2.64	2.95	3.36	3.37	3.64	3.85	*3.83*	*3.95*	Earnings per sh A	*4.25*
1.86	1.86	1.86	1.86	1.70	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.37	1.57	1.76	1.92	*2.03*	Div'd Decl'd per sh B† ■	*2.45*
2.95	3.73	4.78	3.53	3.89	4.73	4.53	5.16	6.39	5.19	5.26	6.85	6.76	4.78	4.68	5.45	*6.05*	*6.05*	Cap'l Spending per sh	*6.00*
20.02	21.82	23.15	23.01	22.54	23.88	24.04	25.77	26.79	27.76	29.17	31.01	33.19	35.07	36.84	38.85	*40.70*	*42.60*	Book Value per sh C	*47.05*
37.61	37.61	37.63	38.02	38.34	42.22	42.66	43.63	45.06	46.92	47.90	49.41	49.95	50.16	50.23	50.27	*50.30*	*50.30*	Common Shs Outst'g D	*50.30*
12.7	10.9	11.4	18.9	26.5	15.5	16.7	15.1	18.2	13.9	10.2	11.8	11.5	12.4	13.4	14.7	*16.4*		Avg Ann'l P/E Ratio	*16.0*
.72	.71	.58	1.03	1.51	.82	.89	.82	.97	.84	.68	.75	.72	.79	.75	.78	*.83*		Relative P/E Ratio	*1.00*
6.0%	4.9%	4.9%	6.0%	6.7%	4.1%	4.1%	3.4%	3.5%	4.0%	4.5%	3.4%	3.1%	3.3%	3.2%	3.1%	3.1%		Avg Ann'l Div'd Yield	*3.6%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $1741.9 mill. Due in 5 Yrs $264.5 mill.
LT Debt $1741.9 mill. LT Interest $81.0 mill.
(LT interest earned: 3.4x)

Pension Assets-12/14 $559.7 mill.
Oblig. $844.8 mill.

Pfd Stock None

Common Stock 50,340,688 shs.
as of 10/23/15

MARKET CAP: $3.4 billion (Mid Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
859.5	926.3	879.4	960.4	1049.8	1036.0	1026.8	1080.7	1246.2	1282.5	*1255*	*1310*	Revenues ($mill)	*1405*
63.7	100.1	82.3	98.4	124.4	142.5	166.9	168.9	182.4	193.5	*195*	*200*	Net Profit ($mill)	*215*
16.9%	13.3%	14.3%	16.3%	15.2%	NMF	NMF	13.4%	28.3%	8.1%	*23.0%*	*23.0%*	Income Tax Rate	*30.0%*
4.7%	4.0%	9.7%	10.2%	10.5%	19.7%	22.8%	7.1%	4.2%	4.4%	*7.5%*	*8.0%*	AFUDC % to Net Profit	*9.5%*
50.0%	45.2%	48.9%	47.6%	50.2%	49.3%	45.6%	45.5%	46.6%	45.3%	*45.0%*	*45.0%*	Long-Term Debt Ratio	*45.0%*
50.0%	54.8%	51.1%	52.4%	49.8%	50.7%	54.4%	54.5%	53.4%	54.7%	*55.0%*	*55.0%*	Common Equity Ratio	*55.0%*
2048.8	2052.8	2364.2	2485.9	2807.1	3020.4	3045.2	3225.4	3465.9	3567.6	*3660*	*3840*	Total Capital ($mill)	*4330*
2314.3	2419.1	2616.6	2758.2	2917.0	3161.4	3406.6	3536.0	3665.0	3833.5	*4095*	*4300*	Net Plant ($mill)	*4975*
4.5%	6.2%	4.7%	5.3%	5.7%	6.0%	6.7%	6.5%	6.4%	6.6%	*6.5%*	*6.0%*	Return on Total Cap'l	*5.5%*
6.2%	8.9%	6.8%	7.6%	8.9%	9.3%	10.1%	9.6%	9.9%	9.9%	*9.0%*	*9.0%*	Return on Shr. Equity	*8.5%*
6.2%	8.9%	6.8%	7.6%	8.9%	9.3%	10.1%	9.6%	9.9%	9.9%	*9.0%*	*9.0%*	Return on Com Equity E	*8.5%*
1.3%	4.3%	2.4%	3.4%	4.8%	5.5%	6.5%	5.7%	5.6%	5.4%	*4.5%*	*4.0%*	Retained to Com Eq	*3.5%*
80%	51%	64%	55%	46%	41%	36%	41%	43%	46%	*52%*	*53%*	All Div'ds to Net Prof	*58%*

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	+2.6	+3.8	+1.4
Avg. Indust. Use (MWH)	N/A	N/A	N/A
Avg. Indust. Revs. per KWH (¢)	4.63	5.21	5.68
Capacity at Peak (Mw)	N/A	N/A	N/A
Peak Load, Summer (Mw)	3245	3407	3184
Annual Load Factor (%)	N/A	N/A	N/A
% Change Customers (yr-end)	+1.1	+1.5	+1.4
Fixed Charge Cov. (%)	283	329	287

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	1.0%	3.0%	*2.5%*
"Cash Flow"	4.5%	6.5%	*2.5%*
Earnings	9.0%	10.0%	*1.0%*
Dividends	--	5.5%	*6.0%*
Book Value	5.0%	6.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	241.1	254.7	334.0	250.9	1080.7
2013	264.9	303.9	381.1	296.3	1246.2
2014	292.7	317.7	382.2	289.8	1282.5
2015	279.4	336.3	369.2	*270.1*	*1255*
2016	*295*	*335*	*395*	*285*	*1310*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.50	.71	1.84	.33	3.37
2013	.70	.93	1.46	.55	3.64
2014	.55	.89	1.73	.69	3.85
2015	.47	1.31	1.46	*.59*	*3.83*
2016	*.55*	*1.20*	*1.63*	*.57*	*3.95*

Cal-endar	QUARTERLY DIVIDENDS PAID B† ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.33	.33	.33	.38	1.37
2013	.38	.38	.38	.43	1.57
2014	.43	.43	.43	.47	1.76
2015	.47	.47	.47	.51	1.92
2016					

BUSINESS: IDACORP, Inc. is the holding company for Idaho Power, a regulated electric utility that serves more than 520,000 customers throughout a 24,000-square-mile area in southern Idaho and eastern Oregon. Operates 17 hydroelectric projects on the Snake River and its tributaries. Also owns three natural gas-fired plants in Idaho and has stakes in three coal-fired facilities (in NV, OR, and WY). Revenue breakdown: residential, 45%; commercial, 27%; industrial, 16%; other, 12%. Fuel sources: hydro, 35%; coal, 34%; natural gas, 7%; purchased power, 24%. '14 depr. rate: 3.8%. Has 2,021 employees. Chairman: Robert A. Tinstman. Pres. & CEO: Darrel T. Anderson. Inc.: Idaho. Address: 1221 W. Idaho St., Boise, ID 83702. Tel.: 208-388-2200. Web: www.idacorpinc.com.

We now suspect that 2015 was a slightly down year for IDACORP. Previously, it looked like the electricity provider to some 500,000 customers in Idaho and Oregon could perhaps eke out a small bottom-line gain for the year that was. However, tough tax-rate comparisons, in particular, probably made for a modest falloff in share net.

The outlook for 2016 seems pretty decent, though. To wit, recent projections point to increased economic activity and population growth within the utility's service area, both of which augur well for power demand. Notably, growth in gross area product (i.e., regional GDP) was recently expected to accelerate from 4.8% in 2015 to around 6.3% over the next 12 months. Meantime, housing construction, including both single-family and multi-family builds, was also forecasted to experience a pick up of sorts.

Major capital investments should drive longer-term rate-base and earnings expansion. Case in point, IDACORP still plans to participate in the construction of a 500-kilovolt transmission line that would run from a substation near Melba, Idaho to Boardman, Oregon. The project is currently slated for completion in 2022 and is expected to cost up to $1.2 billion, some 21% of which would be IDACORP's stake. Importantly, the Boardman line should offer fairly stable power supply in the event that dry conditions limit hydroelectric capacity.

IDACORP has increased its quarterly dividend by 70%, to $0.51 a share, over the past four years. And more increases are likely on the way. Indeed, management recently urged the utility's board of directors to sign off on annual increases of 5% or more (likely above the level of sustainable earnings growth), so that the payout ratio approaches the higher end of a recently targeted range of between 50% and 60%.

IDACORP shares are ranked 3 (Average) for relative year-ahead price performance. At the recent quotation, long-term total return potential doesn't stand out, either. With much of the good news seemingly already reflected in the stock price, we would look elsewhere for utility industry exposure.

Nils C. Van Liew *January 29, 2016*

(A) EPS diluted. Excl. nonrecurring gains (loss): '00, 22¢; '03, 26¢; '05, (24¢); '06, 17¢. Egs. may not sum to total due to rounding. Next earnings report due in early February. (B) Div'ds historically paid in late Feb., May, Aug., and Nov. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred debits. In '14: $25.26/sh. (D) In mill. (E) Rate Base: Net original cost. Rate allowed on com. eq. in Idaho in '11: 9.5%-10.5%; earned on avg. system com. eq., '14: 9.9%. Regulatory Climate: Above Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	85
Earnings Predictability	95

OTTER TAIL CORP. NDQ-OTTR

RECENT PRICE 26.56 | P/E RATIO 16.2 (Trailing: 18.6; Median: 23.0) | RELATIVE P/E RATIO 0.92 | DIV'D YLD 4.7% | VALUE LINE

TIMELINESS 4 Lowered 11/20/15
SAFETY 3 Lowered 12/24/10
TECHNICAL 4 Lowered 12/11/15
BETA .85 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	27.5	32.0	31.9	39.4	46.2	25.4	25.4	23.5	25.3	31.9	32.7	33.4
Low:	23.8	24.0	25.8	29.0	15.0	15.5	18.2	17.5	20.7	25.2	26.5	24.8

Target Price Range 2018 | 2019 | 2020

2018-20 PROJECTIONS

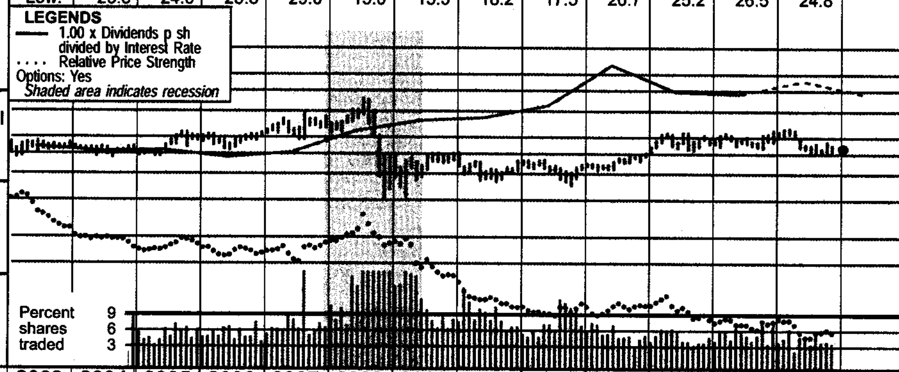
	Price	Gain	Ann'l Total Return
High	50	(+90%)	20%
Low	30	(+15%)	7%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	1	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	1	0

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	50	49	53
to Sell	58	53	50
Hld's(000)	12560	12614	12771



% TOT. RETURN 11/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-3.3	-2.0
3 yr.	24.7	48.1
5 yr.	63.7	71.2

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
19.48	23.45	26.53	27.75	29.28	30.45	35.59	37.43	41.50	37.06	29.03	31.08	29.86	23.76	24.63	21.48	*21.05*	*21.80*	Revenues per sh	*29.15*
2.91	3.21	3.40	3.44	3.30	2.88	3.35	3.39	3.55	2.81	2.76	2.60	2.36	2.71	3.02	3.09	*3.15*	*3.60*	"Cash Flow" per sh	*4.50*
1.45	1.60	1.68	1.79	1.51	1.50	1.78	1.69	1.78	1.09	.71	.38	.45	1.05	1.37	1.55	*1.60*	*1.75*	Earnings per sh A	*2.25*
.99	1.02	1.04	1.06	1.08	1.10	1.12	1.15	1.17	1.19	1.19	1.19	1.19	1.19	1.19	1.21	*1.23*	*1.25*	Div'd Decl'd per sh B ■	*1.32*
1.37	1.85	2.17	2.95	1.97	1.72	2.04	2.35	5.43	7.51	4.95	2.38	2.04	3.20	4.53	4.40	*4.20*	*4.35*	Cap'l Spending per sh	*4.75*
10.30	10.87	11.33	12.25	12.98	14.81	15.80	16.67	17.55	19.14	18.78	17.57	15.83	14.43	14.75	15.39	*16.05*	*16.65*	Book Value per sh C	*18.10*
23.85	23.85	24.65	25.59	25.72	28.98	29.40	29.52	29.85	35.38	35.81	36.00	36.10	36.17	36.27	37.22	*38.00*	*39.00*	Common Shs Outst'g D	*42.00*
13.9	13.5	16.4	16.0	17.8	17.3	15.4	17.3	19.0	30.1	31.2	55.1	47.5	21.7	21.1	18.8	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.79	.88	.84	.87	1.01	.91	.82	.93	1.01	1.81	2.08	3.51	2.98	1.38	1.19	.99	*Value Line*		Relative P/E Ratio	*1.15*
4.9%	4.7%	3.8%	3.7%	4.0%	4.2%	4.1%	3.9%	3.5%	3.6%	5.4%	5.7%	5.6%	5.2%	4.1%	4.1%	*estimates*		Avg Ann'l Div'd Yield	*3.3%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $585.5 mill. **Due in 5 Yrs** $87.0 mill.
LT Debt $498.3 mill. **LT Interest** $28.0 mill.
(LT interest earned: 3.4x)

Leases, Uncapitalized Annual rentals $7 mill.
Pension Assets-12/14 $244.6 mill. **Oblig.** $311.7 mill.
Pfd Stock None

Common Stock 37,743,953 shs.
as of 10/31/15
MARKET CAP: $1.0 billion (Mid Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
1046.4	1105.0	1238.9	1311.2	1039.5	1119.1	1077.9	859.2	893.3	799.3	*800*	*850*	Revenues ($mill)	*1225*
52.9	50.8	54.0	35.1	26.0	13.6	16.4	39.0	50.2	56.9	*60.0*	*70.0*	Net Profit ($mill)	*95.0*
34.6%	34.8%	34.1%	30.0%	--	--	14.5%	5.2%	21.3%	22.5%	*25.0%*	*25.0%*	Income Tax Rate	*25.0%*
1.7%	1.9%	4.2%	6.1%	4.0%	.6%	3.8%	1.7%	1.7%	3.6%	*3.0%*	*4.0%*	AFUDC % to Net Profit	*5.0%*
35.0%	33.5%	38.9%	32.9%	38.8%	40.2%	44.6%	44.0%	42.1%	46.5%	*45.5%*	*45.5%*	Long-Term Debt Ratio	*47.0%*
62.9%	64.5%	59.4%	65.6%	59.8%	58.4%	54.0%	54.4%	57.9%	53.5%	*54.5%*	*54.5%*	Common Equity Ratio	*53.0%*
738.2	763.0	882.1	1032.5	1124.4	1083.3	1058.9	959.2	924.4	1071.3	*1120*	*1190*	Total Capital ($mill)	*1435*
697.1	718.6	854.0	1037.6	1098.6	1108.7	1077.5	1049.5	1167.0	1268.5	*1400*	*1500*	Net Plant ($mill)	*1750*
8.3%	7.7%	7.2%	4.3%	3.4%	2.7%	3.2%	5.7%	6.7%	6.7%	*6.5%*	*7.0%*	Return on Total Cap'l	*8.0%*
11.0%	10.0%	10.0%	5.1%	3.8%	2.1%	2.8%	7.3%	9.4%	9.9%	*10.0%*	*11.0%*	Return on Shr. Equity E	*12.5%*
11.2%	10.2%	10.2%	5.1%	3.8%	2.0%	2.7%	7.3%	9.3%	9.9%	*10.0%*	*11.0%*	Return on Com Equity	*12.5%*
4.2%	3.3%	3.5%	NMF	NMF	NMF	NMF	NMF	1.2%	2.2%	*2.0%*	*3.0%*	Retained to Com Eq	*5.0%*
63%	68%	66%	108%	NMF	NMF	NMF	113%	87%	78%	*79%*	*71%*	All Div'ds to Net Prof	*59%*

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-1.1	+5.8	+4.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	257	359	336

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-2.0%	-8.5%	*4.0%*
"Cash Flow"	-1.0%	-.5%	*7.5%*
Earnings	-2.0%	2.0%	*9.0%*
Dividends	1.0%	--	*1.5%*
Book Value	1.0%	-4.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	219.9	211.4	215.3	212.6	859.2
2013	218.0	212.4	229.8	233.1	893.3
2014	215.0	194.4	196.5	193.4	799.3
2015	202.8	188.2	200.0	*209*	*800*
2016	*215*	*205*	*210*	*220*	*850*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.28	.19	.13	.47	1.05
2013	.41	.21	.41	.35	1.37
2014	.59	.27	.43	.28	1.55
2015	.37	.36	.42	*.45*	*1.60*
2016	*.42*	*.35*	*.48*	*.50*	*1.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.298	.298	.298	.298	1.19
2012	.298	.298	.298	.298	1.19
2013	.298	.298	.298	.298	1.19
2014	.303	.303	.303	.303	1.21
2015	.308	.308	.308	.308	

BUSINESS: Otter Tail Corporation is the parent of Otter Tail Power Company, which supplies electricity to over 130,000 customers in Minnesota (50% of retail elec. revs.), North Dakota (42%), and South Dakota (8%). Electric rev. breakdown, '14: residential, 32%; commercial & farms, 37%; industrial, 25%; other, 6%. Fuel costs: 16.6% of revenues. Also has operations in manufacturing and plastics. 2014 depr. rate: 2.9%. Has 1,893 employees. Off. and dir. own 1.4% of common stock; Cascade Investment, LLC, 9.3%; Vanguard Group, Inc., 6.6%; BlackRock, Inc., 5.5% (2/15 Proxy). CEO: Charles MacFarlane. Inc.: MN. Address: 215 South Cascade St., P.O. Box 496, Fergus Falls, Minnesota 56538-0496. Telephone: 866-410-8780. Internet: www.ottertail.com.

Shares of Otter Tail have traded in a fairly narrow range in recent months, following a selloff earlier in the year. The company reported modest top-line growth for the September period. Electric revenue increased at a good pace, but this was partly offset by lower Product Sales revenue. Still, operating expenses remained muted. Excluding a discontinued gain of $0.07 per share in the prior-year period, earnings from continuing operations would have advanced nicely.

The Electric segment should perform well going forward. Otter Tail Power Company is benefiting from rider recovery increases, greater costs recovered, and healthy customer demand. Earnings from capital investments should also grow. The utility continues to analyze the Environmental Protection Agency's Clean Power Plan to regulate carbon dioxide from existing power plants. Otter Tail will not know the rule's impact on its business until implementation plans are formulated at the state level.

Near-term prospects elsewhere appear mixed. Performance at the Plastics business may well continue to be hurt by weakness in the price of polyvinyl chloride pipe, owing to lower resin prices. Still, we expect a lower cost of product sold will benefit earnings here. Meantime, results at metal fabricator subsidiary BTD Manufacturing should continue to be affected by weakness in agriculture and energy markets, and a reduction in scrap-metal revenue related to lower commodity prices. Performance at this line ought to improve down the road, assuming a more favorable operating climate. Upon completion, the expansion of BTD's Minnesota facilities should enable this business to improve sales by expanding its services. The recent acquisition of Georgia-based Impulse Manufacturing brings strong fabrication capabilities and allows BTD to accelerate its plans to expand into the Southeast to serve that region's growing customer base.

This stock is untimely. But we envision healthy improvement in revenues and share earnings for the company out to 2018-2020. From the recent quotation, this issue offers good total return potential for the coming years. This is supported by a healthy dividend yield.

Michael Napoli, CFA *December 18, 2015*

(A) Diluted earnings. Excl. nonrecurring gains (losses): '99, 34¢; '10, (44¢); '11, 26¢; '13, 2¢; '14, 2¢. Earnings may not sum due to rounding. Next earnings report due in February. (B) Div'ds historically paid in early March, June, Sept., and Dec. ■ Div'd reinvestment plan avail. (C) Incl. intangibles. In '14: $42.7 mill., $1.15/sh. (D) In mill. (E) Regulatory Climate: MN, ND, Average; SD, Above Average.
gains (losses) from discont. operations: '04, 8¢; '05, 33¢; '06, 1¢; '11, ($1.11); '12, ($1.22); '13,

Company's Financial Strength	B+
Stock's Price Stability	85
Price Growth Persistence	15
Earnings Predictability	50

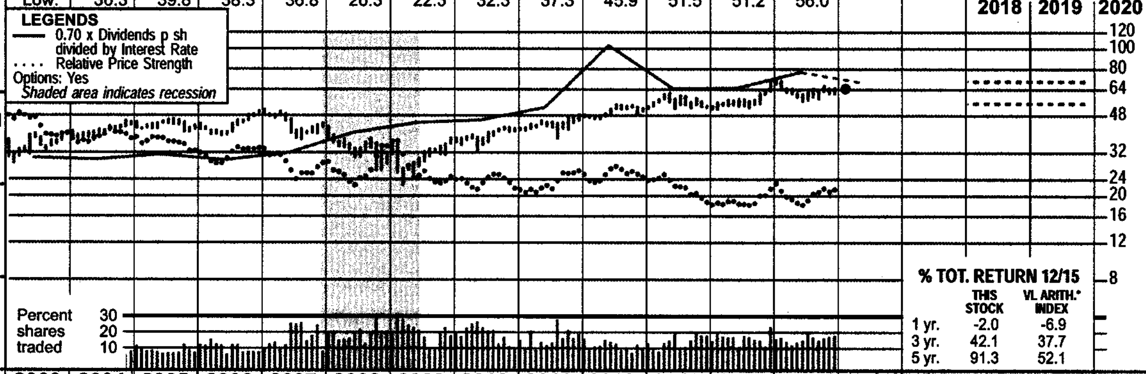
PINNACLE WEST NYSE-PNW

RECENT PRICE	64.88	P/E RATIO	16.4 (Trailing: 18.1 / Median: 15.0)	RELATIVE P/E RATIO	1.00	DIV'D YLD	3.9%	VALUE LINE

TIMELINESS **3** Raised 10/16/15
SAFETY **1** Raised 5/3/13
TECHNICAL **3** Lowered 12/25/15
BETA .75 (1.00 = Market)

High: 45.8	46.7	51.0	51.7	42.9	38.0	42.7	48.9	54.7	61.9	71.1	73.3
Low: 36.3	39.8	38.3	36.8	26.3	22.3	32.3	37.3	45.9	51.5	51.2	56.0

LEGENDS
— 0.70 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2018 | 2019 | 2020

2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+10%)	6%
Low	55	(-15%)	1%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	13	0
to Sell	1	0	0	1	0	0	0	0	1

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	182	175	181
to Sell	194	180	175
Hld's(000)	86769	87394	89339

Percent shares traded 30 20 10

% TOT. RETURN 12/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-2.0	-6.9
3 yr.	42.1	37.7
5 yr.	91.3	52.1

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
28.57	43.50	53.66	28.90	30.87	31.59	30.16	34.03	35.07	33.37	32.50	30.01	29.67	30.09	31.35	31.58	*31.55*	*32.75*	Revenues per sh	*36.50*
7.73	7.99	8.72	7.01	7.33	6.93	5.76	9.70	9.29	8.13	8.08	6.85	7.52	7.92	8.15	8.09	*8.85*	*9.35*	"Cash Flow" per sh	*10.50*
3.18	3.35	3.68	2.53	2.52	2.58	2.24	3.17	2.96	2.12	2.26	3.08	2.99	3.50	3.66	3.58	*3.75*	*4.00*	Earnings per sh A	*4.50*
1.33	1.43	1.53	1.63	1.73	1.83	1.93	2.03	2.10	2.10	2.10	2.10	2.10	2.67	2.23	2.33	2.44	*2.56*	Div'd Decl'd per sh B ■	*2.95*
4.05	7.76	12.27	9.81	7.60	5.86	6.39	7.59	9.37	9.46	7.64	7.03	8.26	8.24	9.36	8.38	*9.90*	*10.40*	Cap'l Spending per sh	*9.75*
26.00	28.09	29.46	29.44	31.00	32.14	34.57	34.48	35.15	34.16	32.69	33.86	34.98	36.20	38.07	39.50	*40.85*	*42.25*	Book Value per sh C	*47.00*
84.83	84.83	84.83	91.26	91.29	91.79	99.08	99.96	100.49	100.89	101.43	108.77	109.25	109.74	110.18	110.57	*111.00*	*111.50*	Common Shs Outst'g D	*118.00*
11.9	11.3	12.0	14.4	14.0	15.8	19.2	13.7	14.9	16.1	13.7	12.6	14.6	14.3	15.3	15.9	*16.8*		Avg Ann'l P/E Ratio	*13.5*
.68	.73	.61	.79	.80	.83	1.02	.74	.79	.97	.91	.80	.92	.91	.86	.84	*.85*		Relative P/E Ratio	*.85*
3.5%	3.8%	3.5%	4.5%	4.9%	4.5%	4.5%	4.7%	4.8%	6.2%	6.8%	5.4%	4.8%	5.3%	4.0%	4.1%	3.9%		Avg Ann'l Div'd Yield	*4.8%*

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
2988.0	3401.7	3523.6	3367.1	3297.1	3263.6	3241.4	3301.8	3454.6	3491.6	*3500*	*3650*	Revenues ($mill)	*4300*
223.2	317.1	298.8	213.6	229.2	330.4	328.2	387.4	406.1	397.6	*420*	*445*	Net Profit ($mill)	*535*
36.2%	33.0%	33.6%	23.4%	36.9%	31.9%	34.0%	36.2%	34.4%	34.2%	*35.0%*	*34.5%*	Income Tax Rate	*34.5%*
10.4%	11.1%	14.8%	17.5%	11.2%	11.7%	12.8%	9.7%	10.0%	11.6%	*11.0%*	*11.0%*	AFUDC % to Net Profit	*8.0%*
43.2%	48.4%	47.0%	46.8%	50.4%	45.3%	44.1%	44.6%	40.0%	41.0%	*44.5%*	*46.5%*	Long-Term Debt Ratio	*45.5%*
56.8%	51.6%	53.0%	53.2%	49.6%	54.7%	55.9%	55.4%	60.0%	59.0%	*55.5%*	*53.5%*	Common Equity Ratio	*54.5%*
6033.4	6678.7	6658.7	6477.6	6686.6	6729.1	6840.9	7171.9	6990.9	7398.7	*8165*	*8765*	Total Capital ($mill)	*10175*
7577.1	7881.9	8436.4	8916.7	9257.8	9578.8	9962.3	10396	10889	11194	*11725*	*12300*	Net Plant ($mill)	*14075*
5.0%	6.2%	5.9%	4.7%	4.8%	6.5%	6.4%	6.8%	7.1%	6.4%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
6.5%	9.2%	8.5%	6.2%	6.9%	9.0%	8.6%	9.8%	9.7%	9.1%	*9.0%*	*9.5%*	Return on Shr. Equity	*9.5%*
6.5%	9.2%	8.5%	6.2%	6.9%	9.0%	8.6%	9.8%	9.7%	9.1%	*9.0%*	*9.5%*	Return on Com Equity E	*9.5%*
1.0%	3.4%	2.5%	.3%	.7%	3.1%	2.8%	4.1%	4.1%	3.5%	*3.5%*	*3.5%*	Retained to Com Eq	*3.5%*
85%	63%	70%	96%	89%	66%	68%	58%	58%	62%	*65%*	*64%*	All Div'ds to Net Prof	*65%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $3725.8 mill. **Due in 5 Yrs** $1486.6 mill.
LT Debt $3257.3 mill. **LT Interest** $159.6 mill.
Incl. $13.4 mill. Palo Verde sale leaseback lessor notes.
(LT interest earned: 4.8x)
Leases, Uncapitalized Annual rentals $18.0 mill.
Pension Assets-12/14 $2615.4 mill.
Oblig. $3078.7 mill.
Pfd Stock None

Common Stock 110,849,752 shs.
as of 10/23/15
MARKET CAP: $7.2 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-.2	-.2	-1.8
Avg. Indust. Use (MWH)	647	644	659
Avg. Indust. Revs. per KWH (¢)	7.86	8.21	8.26
Capacity at Peak (Mw)	8864	8398	9259
Peak Load, Summer (Mw)	7207	6927	7007
Annual Load Factor (%)	48.8	50.0	48.6
% Change Customers (yr-end)	+1.3	+1.4	+1.2
Fixed Charge Cov. (%)	397	419	404

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	--	-1.5%	3.0%
"Cash Flow"	1.5%	-1.0%	4.5%
Earnings	3.5%	8.0%	4.0%
Dividends	3.5%	3.0%	3.5%
Book Value	2.0%	2.0%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	620.6	878.6	1109.5	693.1	3301.8
2013	686.6	915.8	1152.4	699.8	3454.6
2014	686.2	906.3	1172.7	726.4	3491.6
2015	671.2	890.6	1199.1	*739.1*	*3500*
2016	*700*	*975*	*1225*	*750*	*3650*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	d.07	1.12	2.21	.24	3.50
2013	.22	1.18	2.04	.22	3.66
2014	.14	1.19	2.20	.05	3.58
2015	.14	1.10	2.30	*.21*	*3.75*
2016	*.15*	*1.30*	*2.35*	*.20*	*4.00*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.525	.525	.525	.545	2.12
2013	.545	.545	.545	.5675	2.20
2014	.5675	.5675	.5675	.595	2.30
2015	.595	.595	.595	.625	2.41
2016					

BUSINESS: Pinnacle West Capital Corporation is a holding company for Arizona Public Service Company (APS), which supplies electricity to 1.1 million customers in most of Arizona, except about half of the Phoenix metro area, the Tucson metro area, and Mohave County in northwestern Arizona. Discontinued SunCor real estate subsidiary in '10. Electric revenue breakdown: residential, 48%; commercial, 39%; industrial, 5%; other, 9%. Generating sources: coal, 34%; nuclear, 27%; gas & other, 17%; purchased, 22%. Fuel costs: 34% of revenues. Has 6,400 employees. '14 reported deprec. rate: 2.8%. Chairman, President & CEO: Donald E. Brandt. Inc.: AZ. Address: 400 North Fifth St., P.O. Box 53999, Phoenix, AZ 85072-3999. Tel.: 602-250-1000. Internet: www.pinnaclewest.com.

Pinnacle West's utility subsidiary is trying to address the issue of rate design with the Arizona Corporation Commission (ACC). Currently, about 70% of Arizona Public Service's costs of serving residential customers are fixed, but only 10% of its revenues are derived from fixed charges on customers' bills. In addition, because of the way rates are designed, nonsolar customers are subsidizing those users with rooftop solar panels. This is an industrywide problem, and APS is by no means the only utility that is concerned about this. Accordingly, the ACC is conducting hearings with APS and other utilities in the state. Not surprisingly, this has been a highly politicized question. APS will probably file a rate application at the start of June. This case will address the rate design concerns, including information gathered from the current proceedings, as well as seeking some (probably modest) rate relief. New rates (and rate design) would take effect in mid-2017.

The utility will probably begin construction of a gas-fired plant soon. The 510-megawatt facility would cost an estimated $500 million. APS would replace 290 mw of older generating capacity, thereby providing a net increase of 220 mw. This project is expected to be completed in 2019.

We look for a respectable profit increase in 2016. Every year, APS benefits from regulatory mechanisms that provide some revenue — most notably for electric transmission and a portion of the utility's lost revenues that come as a result of conservation measures. Also, the utility is seeing respectable customer growth in its service territory, along with a small amount of sales growth. Our 2016 earnings estimate is within the company's targeted range of $3.90-$4.10 a share.

Finances are strong. The fixed-charge coverage and common-equity ratio are comfortably above the industry averages. Pinnacle West merits a Financial Strength rating of A+.

This top-quality stock offers a dividend yield that is about equal to the utility mean. With the recent quotation above the midpoint of our 2018-2020 Target Price Range, total return potential over that time frame is low.

Paul E. Debbas, CFA *January 29, 2016*

(A) Diluted EPS. Excl. nonrec. losses: '02, 77¢; '09, $1.45; excl. gains (losses) from discontinued ops.: '00, 22¢; '05, (36¢); '06, 10¢; '08, 28¢; '09, (13¢); '10, 18¢; '11, 10¢; '12, (5¢). Next earnings report due mid-Feb. (B) Div'ds historically paid in early Mar., June, Sept., & Dec. There were 5 declarations in '12. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '14: $12.30/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on com. eq. in '12: 10%; earned on avg. com. eq., '14: 9.3%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	75

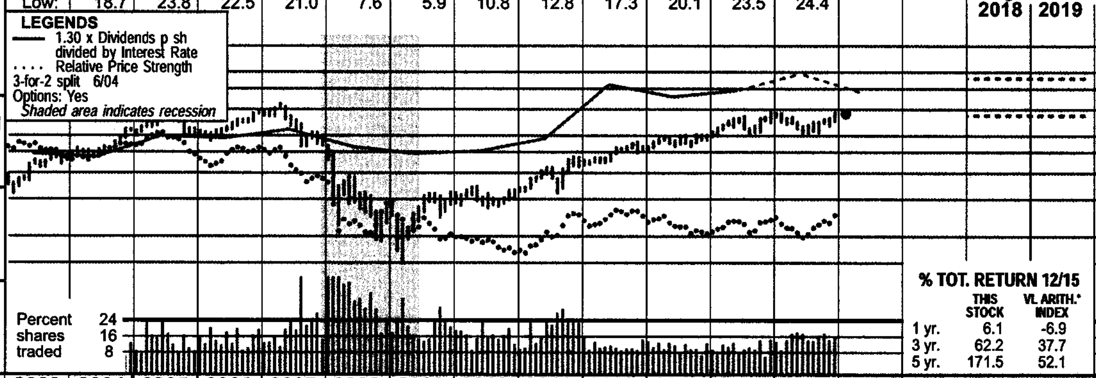
PNM RESOURCES NYSE-PNM

RECENT PRICE 30.55 | P/E RATIO 19.1 (Trailing: 18.5 Median: 17.0) | RELATIVE P/E RATIO 1.16 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS 3 Lowered 6/19/15
SAFETY 3 Lowered 5/9/08
TECHNICAL 3 Raised 1/29/16
BETA .80 (1.00 = Market)

High:	26.1	30.5	32.1	34.3	21.7	13.1	14.0	19.2	22.5	24.5	31.6	31.2
Low:	18.7	23.8	22.5	21.0	7.6	5.9	10.8	12.8	17.3	20.1	23.5	24.4

LEGENDS
—— 1.30 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 6/04
Options: Yes
Shaded area indicates recession



Target Price Range 2018 | 2019 | 2020

2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+45%)	12%
Low	30	(Nil)	3%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	1	0	0	0	0	0	0	0	1
Options	4	0	0	0	0	0	0	0	0
to Sell	4	0	0	0	0	0	0	0	3

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	108	116	99
to Sell	110	104	108
Hld's(000)	69125	69968	71254

Percent shares traded 24 16 8

% TOT. RETURN 12/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	6.1	-6.9
3 yr.	62.2	37.7
5 yr.	171.5	52.1

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
18.96	27.46	40.09	19.92	24.11	26.54	30.19	32.25	24.92	22.65	19.01	19.31	21.35	16.85	17.42	18.03	18.15	18.75	Revenues per sh	20.30
2.82	3.16	4.31	2.83	3.05	3.14	3.56	3.57	2.54	1.76	2.32	2.67	3.18	3.38	3.51	3.62	3.70	3.85	"Cash Flow" per sh	4.70
1.29	1.55	2.61	1.07	1.15	1.43	1.56	1.72	.76	.11	.58	.87	1.08	1.31	1.41	1.45	1.60	1.65	Earnings per sh A	2.35
.53	.53	.53	.57	.61	.63	.79	.86	.91	.61	.50	.50	.50	.58	.68	.76	.80	.88	Div'd Decl'd per sh B ■†	1.30
1.56	2.50	4.51	4.09	2.78	2.25	3.07	4.04	5.94	3.99	3.32	3.25	4.10	3.88	4.37	5.78	5.50	5.50	Cap'l Spending per sh	5.50
14.74	15.76	17.25	16.60	17.84	18.19	18.70	22.09	22.03	18.89	18.90	17.60	19.62	20.05	20.87	22.39	22.10	22.70	Book Value per sh C	25.50
61.05	58.68	58.68	58.68	60.39	60.46	68.79	76.65	76.81	86.53	86.67	86.67	79.65	79.65	79.65	79.65	80.00	80.00	Common Shs Outst'g D	80.00
9.5	8.5	7.3	15.1	14.7	15.0	17.4	15.6	35.6	NMF	18.1	14.0	14.5	15.0	16.1	18.7	17.3		Avg Ann'l P/E Ratio	16.0
.54	.55	.37	.82	.84	.79	.93	.84	1.89	NMF	1.21	.89	.91	.95	.90	.98	.88		Relative P/E Ratio	1.00
4.4%	4.1%	2.8%	3.5%	3.6%	2.9%	2.9%	3.2%	3.4%	4.9%	4.8%	4.1%	3.2%	3.0%	3.0%	2.8%	2.9%		Avg Ann'l Div'd Yield	3.5%

CAPITAL STRUCTURE as of 9/30/15
Total Debt $2208.0 mill. **Due in 5 Yrs** $1112 mill.
LT Debt $1980.4 mill. **LT Interest** $110 mill.
(LT interest earned: 2.4x)
Pension Assets-12/14 $657.6 mill. **Oblig.** $587.7 mill.

Pfd Stock $11.5 mill. **Pfd Div'd** $.5 mill.
115,293 shs. 4.58%, $100 par w/o mandatory redemption. Sinking fund began 2/1/84.

Common Stock 79,653,624 shs. as of 10/23/15
MARKET CAP: $2.4 billion (Mid Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
2076.8	2471.7	1914.0	1959.5	1647.7	1673.5	1700.6	1342.4	1387.9	1435.9	1450	1500	Revenues ($mill)	1625
106.6	122.1	59.9	8.1	53.5	80.0	96.6	105.6	113.5	116.3	130	135	Net Profit ($mill)	190
31.1%	24.7%	5.1%	40.4%	30.4%	32.6%	38.8%	31.4%	31.6%	34.8%	35.0%	35.0%	Income Tax Rate	35.0%
15.6%	4.1%	--	--	6.4%	7.1%	8.8%	7.2%	1.3%	1.3%	1.5%	2.5%	AFUDC % to Net Profit	8.0%
57.4%	50.9%	42.0%	45.6%	48.7%	50.4%	51.5%	50.9%	50.0%	47.8%	52.0%	53.0%	Long-Term Debt Ratio	53.5%
42.3%	48.8%	57.6%	54.0%	51.0%	49.2%	48.1%	48.7%	49.7%	51.9%	48.0%	47.0%	Common Equity Ratio	46.5%
3044.4	3470.7	2935.8	3025.4	3214.9	3100.3	3245.6	3277.9	3344.0	3437.1	3695	3845	Total Capital ($mill)	4385
2984.1	3761.9	2935.4	3192.0	3332.4	3444.4	3627.1	3746.5	3933.9	4270.0	4335	4555	Net Plant ($mill)	5270
4.7%	4.9%	3.4%	1.9%	3.1%	4.2%	4.5%	5.1%	5.2%	5.1%	5.0%	5.0%	Return on Total Cap'l	6.0%
8.2%	7.2%	3.5%	.5%	3.2%	5.2%	6.1%	6.6%	6.8%	6.5%	7.0%	7.5%	Return on Shr. Equity	9.5%
8.2%	7.2%	3.5%	.5%	3.2%	5.2%	6.1%	6.6%	6.8%	6.5%	7.0%	7.5%	Return on Com Equity E	9.5%
4.3%	3.7%	NMF	NMF	.4%	2.2%	3.3%	3.8%	3.7%	3.2%	3.5%	3.5%	Retained to Com Eq	3.5%
48%	49%	117%	NMF	86%	58%	47%	43%	45%	51%	51%	51%	All Div'ds to Net Prof	55%

ELECTRIC OPERATING STATISTICS F

	2012	2013	2014
% Change Retail Sales (KWH)	-1.6	-2.9	-2.1
Avg. Indust. Use (MWH)	N/A	N/A	N/A
Avg. Indust. Revs. per KWH (¢)	N/A	N/A	N/A
Capacity at Peak (Mw)	2537	2572	2707
Peak Load, Summer (Mw)	1948	2008	1948
Annual Load Factor (%)	N/A	N/A	N/A
% Change Customers (yr-end)	+.4	+.7	+.6
Fixed Charge Cov. (%)	225	241	250

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-3.0%	-4.5%	1.5%
"Cash Flow"	1.5%	9.5%	5.0%
Earnings	1.5%	23.5%	9.0%
Dividends	1.0%	--	10.0%
Book Value	2.0%	1.0%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	305.4	323.9	390.4	322.7	1342.4
2013	317.7	347.6	399.7	322.9	1387.9
2014	328.9	346.2	413.9	346.9	1435.9
2015	332.9	352.9	417.4	346.8	1450
2016	345	360	440	355	1500

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.17	.33	.69	.13	1.31
2013	.18	.38	.64	.21	1.41
2014	.16	.36	.69	.24	1.45
2015	.21	.44	.76	.19	1.60
2016	.25	.40	.75	.25	1.65

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.145	.145	.145	.145	.58
2013	.145	.165	.165	.165	.64
2014	.185	.185	.185	.185	.74
2015	.20	.20	.20	.20	.80
2016	.22				

BUSINESS: PNM Resources is an investor-owned holding company of energy and energy related businesses. Primary subsidiaries include Public Service Company of New Mexico (PNM) and Texas-New Mexico Power Company (TNMP), which generate, transmit, and distribute electricity in New Mexico and Texas. Sold First Choice Energy (9/11) and gas utility operations (1/09). Electric rev. breakdown '14: residential, 37%; commercial, 37%; industrial, 6%; other, 20%. Fuels: coal, 57%; nuclear, 30%; gas/oil, 12%; solar, 1%. Fuel costs: 49% of revenues. '14 depreciation rate: 3.3%. Has 1,881 employees. Chairman, President & CEO: Patricia K. Collawn. Inc.: NM. Address: 414 Silver Ave. SW, Albuquerque, NM. 87102. Tel.: 505-241-2700. Internet: www.pnmresources.com.

PNM Resources recently got the go-ahead from state regulators to move forward with its clean power plan. Indeed, the New Mexico Public Regulatory Commission in mid-December formally approved the utility's proposed shutdown of two coal-fired units at the San Juan Generating Station (SJGS) in the northern part of the state by the end of 2017. Meantime, the remaining (two) SJGS coal units were recently retrofitted with new emission controls, while other facilities, including a 40-megawatt solar installation, are now slated to fill the breach. Part of a broader effort to meet clean-air mandates, the moves recently needed additional approvals to proceed.

The utility recently said that it expects to earn between $1.55 and $1.76 a share in 2016. Based on a company-issued 2015 baseline ($1.56-$1.61), the target range implies as much as 13% bottom-line growth down to a modest (less than 4%) decline this year. The wide variance largely reflects the uncertain timing of a rate hike by PNM's Public Service of New Mexico (PNM) unit. Notably, a three-month implementation delay (October 1st versus July 1st) could nick earnings by 12%, or $0.21 a share.

Stretch goals include 7%-9% earnings growth through 2019. Key to reaching the mark will be PNM's ability to earn authorized returns on its regulated businesses, which isn't a given. Among additional concerns is a New Mexico economy that is highly dependent on public works projects and which has been growing at a slow pace compared to the nation as a whole.

The board of directors recently authorized a 10% dividend hike. The higher quarterly distribution ($0.22 a share) will first be paid on February 12th, to shareholders of record on January 25th. On an annualized basis, it represents a serviceable 50%-64% of PNM's targeted 2016 earnings.

Shares of PNM Resources are ranked 3 (Average) for relative year-ahead price performance. At the recent quotation, long-term total return potential doesn't stand out, either. Recent dividend hikes are encouraging, but more-competitive yields can be found elsewhere.

Nils C. Van Liew *January 29, 2016*

(A) EPS dil. Excl. n/r gains (losses): '99, 8¢; '00, 21¢; '01, (15¢); '03, 67¢; '05, (56¢); '08, ($3.77); '10, ($1.36); '11, 88¢. '13, (16); Excl. disc. ops.: '08, 42¢; '09, 78¢. Egs. may not sum due to rounding. Next egs. rpt. due late February. (B) Div'ds hist. pd. in Feb., May, Aug., Nov. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. '14: $3.49/sh. (D) In mill., adjust. for split. (E) Rate base: net orig. cost. ROE allowed in '11: 10.0%; earned on avg. com. eq., '13: 10.0%. Reg. Climate: Avg. (F) Excl. First Choice.

Company's Financial Strength	B
Stock's Price Stability	85
Price Growth Persistence	45
Earnings Predictability	35

PORTLAND GENERAL NYSE-POR

RECENT PRICE 37.69 | P/E RATIO 16.8 (Trailing: 18.8 / Median: NMF) | RELATIVE P/E RATIO 1.02 | DIV'D YLD 3.3% | VALUE LINE

TIMELINESS 3 Raised 8/14/15
SAFETY 2 Raised 5/4/12
TECHNICAL 3 Lowered 12/4/15
BETA .80 (1.00 = Market)

High:	35.0	31.3	27.7	21.4	22.7	26.0	28.1	33.3	40.3	41.0	
Low:	24.2	25.5	15.4	13.5	17.5	21.3	24.3	27.4	29.0	33.0	

Target Price Range
2018 | 2019 | 2020

2018-20 PROJECTIONS

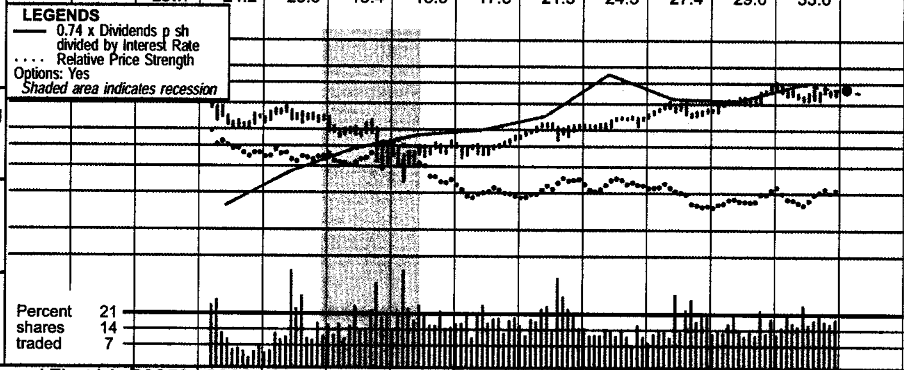
	Price	Gain	Ann'l Total Return
High	40	(+5%)	5%
Low	30	(-20%)	-1%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	0	1	0	0	0	2	0	1

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	122	112	113
to Sell	142	136	110
Hld's(000)	84710	86966	86675



% TOT. RETURN 12/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-0.6	-6.9
3 yr.	46.0	37.7
5 yr.	100.2	52.1

On April 3, 2006, Portland General Electric's existing stock (which was owned by Enron) was canceled, and 62.5 million shares were issued to Enron's creditors or the Disputed Claims Reserve (DCR). The stock began trading on a when-issued basis that day, and regular trading began on April 10, 2006. Shares issued to the DCR were released over time to Enron's creditors until all of the remaining shares were released in June, 2007.

2005G	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
23.14	24.32	27.87	27.89	23.99	23.67	24.06	23.89	23.18	24.29	*21.10*	*22.45*	Revenues per sh	*24.25*
4.75	4.64	5.21	4.71	4.07	4.82	4.96	5.15	4.93	6.08	*5.40*	*5.90*	"Cash Flow" per sh	*7.00*
1.02	1.14	2.33	1.39	1.31	1.66	1.95	1.87	1.77	2.18	*2.05*	*2.35*	Earnings per sh A	*2.75*
--	.68	.93	.97	1.01	1.04	1.06	1.08	1.10	1.12	1.18	*1.26*	Div'd Decl'd per sh B ■ †	*1.50*
4.08	5.94	7.28	6.12	9.25	5.97	3.98	4.01	8.40	12.87	*6.80*	*5.00*	Cap'l Spending per sh	*3.25*
19.15	19.58	21.05	21.64	20.50	21.14	22.07	22.87	23.30	24.43	*25.40*	*26.45*	Book Value per sh C	*29.75*
62.50	62.50	62.53	62.58	75.21	75.32	75.36	75.56	78.09	78.23	*88.90*	*89.10*	Common Shs Outst'g D	*89.70*
--	23.4	11.9	16.3	14.4	12.0	12.4	14.0	16.9	15.3	*17.6*		Avg Ann'l P/E Ratio	*12.5*
--	1.26	.63	.98	.96	.76	.78	.89	.95	.81	*.90*		Relative P/E Ratio	*.80*
--	2.5%	3.3%	4.3%	5.4%	5.2%	4.4%	4.1%	3.7%	3.3%	3.3%		Avg Ann'l Div'd Yield	*4.4%*
1446.0	1520.0	1743.0	1745.0	1804.0	1783.0	1813.0	1805.0	1810.0	1900.0	*1875*	*2000*	Revenues ($mill)	*2175*
64.0	71.0	145.0	87.0	95.0	125.0	147.0	141.0	137.0	175.0	*175*	*210*	Net Profit ($mill)	*245*
40.2%	33.6%	33.8%	28.7%	28.8%	30.5%	28.3%	31.4%	23.2%	26.0%	*21.5%*	*21.5%*	Income Tax Rate	*21.5%*
18.8%	33.8%	17.9%	17.2%	31.6%	17.6%	5.4%	7.1%	14.6%	33.7%	*15.0%*	*7.0%*	AFUDC % to Net Profit	*3.0%*
42.3%	43.4%	49.9%	46.2%	50.3%	53.0%	49.6%	47.1%	51.3%	52.7%	*49.5%*	*49.5%*	Long-Term Debt Ratio	*49.5%*
57.7%	56.6%	50.1%	53.8%	49.7%	47.0%	50.4%	52.9%	48.7%	47.3%	*50.5%*	*50.5%*	Common Equity Ratio	*50.5%*
2076.0	2161.0	2629.0	2518.0	3100.0	3390.0	3298.0	3264.0	3735.0	4037.0	*4460*	*4675*	Total Capital ($mill)	*5325*
2436.0	2718.0	3066.0	3301.0	3858.0	4133.0	4285.0	4392.0	4880.0	5679.0	*5980*	*6110*	Net Plant ($mill)	*6025*
4.6%	4.7%	6.9%	5.0%	4.5%	5.4%	6.2%	5.9%	5.1%	5.8%	*5.0%*	*5.5%*	Return on Total Cap'l	*6.0%*
5.3%	5.8%	11.0%	6.4%	6.2%	7.9%	8.8%	8.2%	7.5%	9.2%	*7.5%*	*9.0%*	Return on Shr. Equity	*9.0%*
5.3%	5.8%	11.0%	6.4%	6.2%	7.9%	8.8%	8.2%	7.5%	9.2%	*7.5%*	*9.0%*	Return on Com Equity E	*9.0%*
5.3%	3.5%	6.6%	2.0%	1.5%	3.0%	4.1%	3.5%	2.9%	4.6%	*3.5%*	*4.5%*	Retained to Com Eq	*4.0%*
--	39%	40%	69%	76%	62%	54%	57%	61%	50%	*56%*	*53%*	All Div'ds to Net Prof	*54%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $2204 mill. **Due in 5 Yrs** $510 mill.
LT Debt $2204 mill. **LT Interest** $115 mill.
(LT interest earned: 2.0x)
Leases, Uncapitalized Annual rentals $10 mill.

Pension Assets-12/14 $591 mill.
Oblig. $777 mill.

Pfd Stock None

Common Stock 88,772,420 shs.
as of 10/16/15

MARKET CAP: $3.3 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-.8	+1.2	-.8
Avg. Indust. Use (MWH)	16409	16258	16577
Avg. Indust. Revs. per KWH (¢)	5.26	4.84	5.13
Capacity at Peak (Mw)	4173	4380	4910
Peak Load, Winter (Mw) F	3597	3869	3866
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.7	+.9	+.7
Fixed Charge Cov. (%)	270	239	248

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	--	-2.0%	*.5%*
"Cash Flow"	--	3.0%	*4.5%*
Earnings	--	3.0%	*6.0%*
Dividends	--	2.5%	*5.5%*
Book Value	--	2.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	479.0	413.0	450.0	463.0	1805.0
2013	473.0	403.0	435.0	499.0	1810.0
2014	493.0	423.0	484.0	500.0	1900.0
2015	473.0	450.0	476.0	*476*	*1875*
2016	*525*	*460*	*505*	*510*	*2000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.65	.34	.50	.38	1.87
2013	.65	.13	.40	.59	1.77
2014	.73	.43	.47	.55	2.18
2015	.62	.44	.40	*.59*	*2.05*
2016	*.80*	*.45*	*.45*	*.65*	*2.35*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.265	.265	.27	.27	1.07
2013	.27	.27	.275	.275	1.09
2014	.275	.275	.28	.28	1.11
2015	.28	.28	.30	.30	1.16
2016	.30				

BUSINESS: Portland General Electric Company (PGE) provides electricity to 852,000 customers in 52 cities in a 4,000-square-mile area of Oregon, including Portland and Salem. The company is in the process of decommissioning the Trojan nuclear plant, which it closed in 1993. Electric revenue breakdown: residential, 47%; commercial, 34%; industrial, 12%; other, 7%. Generating sources: coal, 21%; gas, 16%; hydro, 8%; wind, 6%; purchased, 49%. Fuel costs: 38% of revenues. '14 reported depreciation rate: 3.6%. Has 2,600 employees. Chairman: Jack E. Davis. President and Chief Executive Officer: James J. Piro. Incorporated: Oregon. Address: 121 S.W. Salmon Street, Portland, Oregon 97204. Telephone: 503-464-8000. Internet: www.portlandgeneral.com.

The Oregon Public Utility Commission has approved a regulatory settlement for Portland General Electric. At the start of 2016, PGE's rates were *lowered* by $15 million. The reduction reflects, in part, lower net variable power costs that are being passed through to ratepayers. Then, when the Carty gas-fired generating plant begins commercial operation (as long as this is no later than July 31st), the utility's rates would rise by $85 million. The allowed return on equity is 9.6%, and the new rates reflect a common-equity ratio of 50%. However . . .

The Carty plant has run into a construction problem. Initially, the 440-megawatt facility was expected to enter service in the second quarter of 2016 at a cost of $514 million. But the company that was building the plant went bankrupt and ceased construction. PGE took control of the site, and construction has resumed, although it took some time for it to ramp back up. What effect this will have on the cost and timing of the project is unknown. Management plans to provide an update when the utility reports earnings in mid-February.

We still expect a significant profit increase in 2016. Once Carty begins commercial operation, PGE will benefit from the associated rate relief. (At this point, we are not assuming that the delay will have a major effect on the utility's income.) Also, a year ago PGE's service area experienced its warmest winter on record. This made the first-quarter comparison easy. The utility is benefiting from growth in its service area's economy.

Is this company a takeover candidate? With increased merger and acquisition activity in the electric utility industry, PGE is considered in some circles as a prospective acquiree. However, investors should be aware that, more than 10 years ago, a proposed buyout of the company fell through. Thus, we do not advise purchase of this issue in the hope of a buyout.

This stock's dividend yield is slightly below the industry average. Although we project respectable dividend growth over the 3- to 5-year time frame, with the recent quotation above the midpoint of our 2018-2020 Target Price Range, total return potential is unappealing.

Paul E. Debbas, CFA *January 29, 2016*

(A) Diluted EPS. Excl. nonrecurring loss: '13, 42¢. Next earnings report due mid-Feb. (B) Dividends paid mid-Jan., Apr., July, and Oct. ■ Dividend reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '14: $6.31/sh. (D) In mill. (E) Rate base: Net original cost. Rate allowed on com. eq. in '16: 9.6%; earned on avg. com. eq., '14: 9.4%. Regulatory Climate: Average. (F) Summer peak in '12. (G) '05 per-share data are pro forma, based on shares outstanding when stock began trading in '06.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	70

WESTAR ENERGY NYSE-WR

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
41.40	17.5 (Trailing: 19.3 Median: 14.0)	0.99	3.5%

VALUE LINE

TIMELINESS 3 Lowered 12/12/14
SAFETY 2 Raised 4/1/05
TECHNICAL 2 Raised 12/18/15
BETA .75 (1.00 = Market)

High:	22.9	25.0	27.2	28.6	25.9	22.3	25.9	29.0	33.0	35.0	43.2	44.0
Low:	18.1	21.1	20.1	22.8	16.0	14.9	20.6	22.6	26.8	28.6	31.7	33.9

Target Price Range
2018 | 2019 | 2020

2018-20 PROJECTIONS

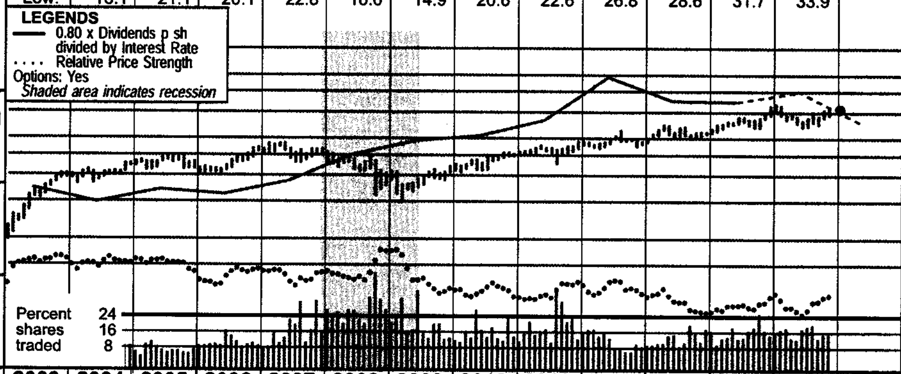
	Price	Gain	Ann'l Total Return
High	55	(+35%)	11%
Low	40	(-5%)	3%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	5	0	1	0	0	1	0

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	134	146	137
to Sell	155	125	121
Hld's(000)	97474	97324	99969



% TOT. RETURN 11/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.5	-2.0
3 yr.	68.3	48.1
5 yr.	113.3	71.2

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
30.21	33.80	31.20	24.77	20.06	17.02	18.23	18.37	18.09	16.98	17.04	18.34	17.27	17.88	18.48	19.76	*18.45*	*18.60*	Revenues per sh	*18.70*
7.51	6.96	5.32	4.77	3.77	3.12	3.28	3.94	3.77	3.14	3.59	4.24	3.97	4.30	4.41	4.55	*4.40*	*4.75*	"Cash Flow" per sh	*5.45*
1.48	.89	d.58	1.00	1.48	1.17	1.55	1.88	1.84	1.31	1.28	1.80	1.79	2.15	2.27	2.35	*2.25*	*2.45*	Earnings per sh A	*3.10*
2.14	1.44	1.20	1.20	.87	.80	.92	.98	1.08	1.16	1.20	1.24	1.28	1.32	1.36	1.40	*1.44*	*1.50*	Div'd Decl'd per sh B■†	*1.70*
4.09	4.40	3.37	1.89	2.06	2.19	2.45	3.95	7.84	8.65	5.26	4.82	5.55	6.40	6.08	6.47	*6.50*	*7.00*	Cap'l Spending per sh	*7.95*
27.83	27.20	25.97	13.68	14.23	16.13	16.31	17.62	19.14	20.18	20.59	21.25	22.03	22.89	23.88	25.02	*25.25*	*26.75*	Book Value per sh C	*28.55*
67.40	70.08	70.08	71.51	72.84	86.03	86.84	87.39	95.46	108.31	109.07	112.13	125.70	126.50	128.25	131.69	*140.00*	*145.00*	Common Shs Outst'g E	*155.00*
17.2	20.6	--	14.0	10.8	17.4	14.8	12.2	14.1	17.0	14.9	13.0	14.8	13.4	14.0	15.4	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.98	1.34	--	.76	.62	.92	.79	.66	.75	1.02	.99	.83	.93	.85	.79	.81	*Value Line*		Relative P/E Ratio	*.95*
8.4%	7.9%	5.8%	8.6%	5.5%	3.9%	4.0%	4.3%	4.2%	5.2%	6.3%	5.3%	4.8%	4.6%	4.3%	3.9%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $3245.5 mill. Due in 5 Yrs $1000 mill.
LT Debt $2941.9 mill. LT Interest $120.0 mill.
(LT interest earned: 2.7x)

Pension Assets 12/14 $661 mill. Oblig. $914 mill.

Pfd Stock None

Common Stock 141,838,178 shs.
MARKET CAP: $5.9 billion (Large Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
1583.3	1605.7	1726.8	1839.0	1858.2	2056.2	2171.0	2261.5	2370.7	2601.7	*2580*	*2700*	Revenues ($mill)	*2900*
134.9	165.3	168.4	136.8	141.3	203.9	214.0	275.1	292.5	313.3	*315*	*355*	Net Profit ($mill)	*480*
31.0%	25.4%	27.5%	24.8%	29.4%	29.0%	35.2%	30.9%	33.1%	31.9%	*30.0%*	*30.0%*	Income Tax Rate	*30.0%*
--	--	10.4%	--	--	--	--	--	10.4%	10.0%	*10.0%*	*10.0%*	AFUDC % to Net Profit	*10.0%*
52.1%	50.0%	50.6%	49.8%	53.4%	53.6%	49.5%	51.2%	50.0%	50.0%	*50.0%*	*50.0%*	Long-Term Debt Ratio	*50.0%*
47.2%	49.3%	48.9%	49.7%	46.1%	46.0%	50.1%	48.8%	50.0%	50.0%	*50.0%*	*50.0%*	Common Equity Ratio	*50.0%*
3000.4	3124.2	3738.3	4400.1	4866.8	5180.9	5531.0	5938.2	6131.1	6596.2	*6650*	*6800*	Total Capital ($mill)	*7500*
3947.7	4071.6	4803.7	5533.5	5771.7	6309.5	6745.4	7335.7	7848.5	8441.5	*8500*	*8600*	Net Plant ($mill)	*9000*
6.2%	6.7%	5.8%	4.2%	4.4%	5.5%	5.3%	6.0%	6.1%	6.0%	*6.0%*	*6.0%*	Return on Total Cap'l	*7.0%*
9.4%	10.6%	9.1%	6.2%	6.2%	8.5%	7.7%	9.5%	9.6%	9.5%	*9.5%*	*9.5%*	Return on Shr. Equity	*9.5%*
9.5%	10.7%	9.2%	6.2%	6.3%	8.5%	7.7%	9.4%	9.6%	9.5%	*9.5%*	*9.5%*	Return on Com Equity D	*9.5%*
4.3%	5.5%	4.3%	1.2%	.8%	3.1%	2.7%	4.0%	4.2%	4.3%	*4.5%*	*4.5%*	Retained to Com Eq	*5.0%*
55%	49%	53%	80%	87%	63%	65%	57%	56%	55%	*64%*	*61%*	All Div'ds to Net Prof	*55%*

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-1.5	+3.6	+1.5
Avg. Indust. Use (MWH)	5588	5407	5747
Avg. Indust. Revs. per KWH (¢)	6.60	6.47	6.72
Capacity at Peak (Mw)	6557	6671	6698
Peak Load, Summer (Mw)	5411	5489	5226
Annual Load Factor (%)	56.0	55.9	56.2
% Change Customers (yr-end)	+.2	+.2	+.2
Fixed Charge Cov. (%)	319	323	332

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-1.0%	1.5%	*2.5%*
"Cash Flow"	1.5%	5.0%	*4.5%*
Earnings	6.5%	9.0%	*6.0%*
Dividends	3.5%	3.5%	*3.0%*
Book Value	5.0%	3.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	475.7	566.3	695.8	523.7	2261.5
2013	546.2	569.6	695.0	559.9	2370.7
2014	628.6	612.7	764.0	596.4	2601.7
2015	590.8	589.6	732.8	*666.8*	*2580*
2016	*645*	*630*	*775*	*650*	*2700*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.21	.48	1.09	.37	2.15
2013	.40	.52	1.04	.31	2.27
2014	.52	.40	1.10	.33	2.35
2015	.38	.46	.97	*.44*	*2.25*
2016	*.50*	*.45*	*1.10*	*.40*	*2.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.31	.32	.32	.32	1.27
2012	.32	.33	.33	.33	1.31
2013	.33	.34	.34	.34	1.35
2014	.34	.35	.35	.35	1.39
2015	.35	.36	.36	.36	

BUSINESS: Westar Energy, Inc., formerly Western Resources, is the parent of Kansas Gas & Electric Company. Westar supplies electricity to 700,000 customers in Kansas. Electric revenue sources: residential and rural, 41%; commercial, 38%; industrial, 21%. Sold investment in ONEOK in 2003 and 85% ownership in Protection One in 2004. 2014 depreciation rate: 3.9%. Estimated plant age: 16 years. Fuels: coal, 48%; nuclear, 8%; gas, 44%. Has 2,411 employees. BlackRock Inc owns 7.2% of common; The Vanguard Group owns 6.3%; Stowers Institute owns 5.7% (4/15 proxy). CEO and Pres.: Mark A. Ruelle. Inc.: Kansas. Addr.: 818 South Kansas Avenue, Topeka, Kansas 66612. Telephone: 785-575-6300. Internet: www.westarenergy.com.

Regulators approved a $78 million rate hike for Westar Energy. The Kansas Corporation Commission accepted a 4%, or $78 million, rate increase that should help cover some of the utility's costs associated with upgrading several power plants. Westar Energy originally sought a $152 million boost, but subsequently dropped that demand to $78 million after failing to garner enough support from lawmakers. Utilities routinely ask for relatively large rate increases that often get negotiated down by legislators, so the outcome was not at all unexpected.

Much of the new revenue will cover the cost of upgrades at the La Cygne Energy Center and Wolf Creek. Improvements at La Cygne were required by federal air pollution standards. The facility received a baghouse, wet scrubber, and selective catalytic reduction (SCR) to reduce emissions. At Wolf Creek, the upgrades were tied to a decision to keep the plant in operation for 20 years longer than initially planned, until 2045.

Westar continues to modernize electricity production. The company announced plans to phase out by yearend old electrical-generating equipment at three locations. That should help reduce carbon emissions and energy waste, while also lowering operational costs at several plants. Furthermore, management will add more renewable energy production in the coming months as this appears to be a reasonable alternative to investing in more electrical-generating equipment.

We look for a dividend hike at the upcoming board meeting. The increase will likely add a penny to the quarterly distribution, in line with the pattern in recent years. Also, Westar Energy is targeting a payout ratio of 50%-60%, so we expect only moderate dividend growth potential through the 3- to 5-year period.

This stock provides a steady source of income for conservative investors. The yield is around the average for electric utilities, and the payout has been raised every year since 2003. In addition, we expect cost-control measures and higher rates to drive above-average earnings growth over the next few years. That should allow Westar to increase the dividend uninterrupted.

Daniel Henigson *December 18, 2015*

(A) EPS diluted from 2010 onward. Excl. nonrecur. gains (losses): '99, ($1.31); '00, $1.07; '01, 27¢; '02, ($12.06); '03, 77¢; '08, 39¢; '11, 14¢. Earnings may not sum due to rounding. Next egs. rep't due early February. (B) Div'ds paid in early Jan., April, July, and Oct. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. reg. assets. In 2014: $6.48/sh. (D) Rate base determined: fair value; Rate allowed on common equity in '14: 10.0%; earned on avg. com. eq., '14: 9.5%. Regul. Clim.: Avg. (E) In mill.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	85

ATTACHMENT C

ALLETE, Inc. (ALE) - NYSE Watchlist

Like 13

53.31 0.14(0.26%) 1:42PM EST - NYSE Real Time Price

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.78	0.89	3.33	3.31
No. of Analysts	4.00	1.00	4.00	5.00
Low Estimate	0.73	0.89	3.05	3.28
High Estimate	0.82	0.89	3.44	3.36
Year Ago EPS	0.73	0.91	2.99	3.33

Next Earnings Date: Feb 18, 2016 - Set a Reminder

Revenue Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	417.00M	NaN	1.33B	1.32B
No. of Analysts	1		4	4
Low Estimate	417.00M	NaN	1.21B	1.22B
High Estimate	417.00M	NaN	1.52B	1.42B
Year Ago Sales	290.70M	NaN	1.14B	1.33B
Sales Growth (year/est)	43.40%	N/A	16.60%	-0.40%

Earnings History	Dec 14	Mar 15	Jun 15	Sep 15
EPS Est	0.68	0.87	0.50	1.02
EPS Actual	0.73	0.91	0.48	1.25
Difference	0.05	0.04	-0.02	0.23
Surprise %	7.40%	4.60%	-4.00%	22.50%

EPS Trends	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.78	0.89	3.33	3.31
7 Days Ago	0.78	0.89	3.33	3.31
30 Days Ago	0.78	0.89	3.34	3.31
60 Days Ago	0.82	0.97	3.30	3.35
90 Days Ago	0.83	0.98	3.30	3.38

EPS Revisions	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	0	0	0	0
Up Last 30 Days	1	0	0	0
Down Last 30 Days	0	0	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	ALE	Industry	Sector	S&P 500
Current Qtr.	6.80%	-10.50%	47.40%	2.90%
Next Qtr.	-2.20%	21.90%	49.80%	13.10%
This Year	11.40%	13.00%	22.80%	2.60%
Next Year	-0.60%	1.80%	8.00%	9.30%
Past 5 Years (per annum)	10.35%	N/A	N/A	N/A
Next 5 Years (per annum)	5.00%	7.67%	6.15%	4.91%
Price/Earnings (avg. for comparison categories)	16.08	8.46	19.13	19.73
PEG Ratio (avg. for comparison categories)	3.22	3.67	3.29	1.98

American Electric Power Co., Inc. (AEP) - NYSE Watchlist

Like 62

61.88 0.40(0.64%) 1:45PM EST - NYSE Real Time Price

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Mar 16	Next Qtr. Jun 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	1.14	0.85	3.70	3.91
No. of Analysts	12.00	12.00	23.00	18.00
Low Estimate	0.93	0.76	3.54	3.80
High Estimate	1.27	0.92	3.76	4.00
Year Ago EPS	1.28	0.88	3.69	3.70

Revenue Est	Current Qtr. Mar 16	Next Qtr. Jun 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	4.51B	3.98B	17.21B	17.63B
No. of Analysts	7	7	15	11
Low Estimate	4.13B	3.64B	16.19B	15.90B
High Estimate	4.92B	4.46B	18.25B	18.87B
Year Ago Sales	4.70B	3.90B	16.50B	17.21B
Sales Growth (year/est)	-4.00%	2.20%	4.30%	2.50%

Earnings History	Mar 15	Jun 15	Sep 15	Dec 15
EPS Est	1.10	0.81	1.01	0.50
EPS Actual	1.28	0.88	1.06	0.48
Difference	0.18	0.07	0.05	-0.02
Surprise %	16.40%	8.60%	5.00%	-4.00%

EPS Trends	Current Qtr. Mar 16	Next Qtr. Jun 16	Current Year Dec 16	Next Year Dec 17
Current Estimate	1.14	0.85	3.70	3.91
7 Days Ago	1.14	0.85	3.71	3.91
30 Days Ago	1.16	0.86	3.71	3.90
60 Days Ago	1.15	0.87	3.72	3.91
90 Days Ago	1.16	0.87	3.72	3.90

EPS Revisions	Current Qtr. Mar 16	Next Qtr. Jun 16	Current Year Dec 16	Next Year Dec 17
Up Last 7 Days	0	2	1	2
Up Last 30 Days	2	4	4	6
Down Last 30 Days	0	0	2	1
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	AEP	Industry	Sector	S&P 500
Current Qtr.	-10.90%	-10.50%	47.40%	2.90%
Next Qtr.	-3.40%	21.90%	49.80%	13.10%
This Year	0.30%	13.00%	22.80%	2.60%
Next Year	5.70%	1.80%	8.00%	9.30%
Past 5 Years (per annum)	5.46%	N/A	N/A	N/A
Next 5 Years (per annum)	4.55%	7.67%	6.15%	4.91%
Price/Earnings (avg. for comparison categories)	16.84	8.46	19.13	19.73
PEG Ratio (avg. for comparison categories)	3.70	3.67	3.29	1.98

Currency in USD.

El Paso Electric Co. (EE) - NYSE ★ Watchlist

41.04 0.25(0.61%) 1:47PM EST - Nasdaq Real Time Price

Analyst Estimates

Earnings Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.00	N/A	2.00	2.55
No. of Analysts	1.00	N/A	4.00	4.00
Low Estimate	0.00	N/A	1.98	2.50
High Estimate	0.00	N/A	2.03	2.58
Year Ago EPS	0.10	0.09	2.27	2.00

Next Earnings Date: Feb 24, 2016 - Set a Reminder

Revenue Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	NaN	NaN	898.70M	924.37M
No. of Analysts			3	3
Low Estimate	NaN	NaN	872.00M	898.00M
High Estimate	NaN	NaN	926.50M	939.80M
Year Ago Sales	NaN	NaN	601.72M	898.70M
Sales Growth (year/est)	N/A	N/A	49.40%	2.90%

Earnings History	Dec 14	Mar 15	Jun 15	Sep 15
EPS Est	0.11	0.12	0.60	1.20
EPS Actual	0.10	0.09	0.52	1.40
Difference	-0.01	-0.03	-0.08	0.20
Surprise %	-9.10%	-25.00%	-13.30%	16.70%

EPS Trends	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.00	N/A	2.00	2.55
7 Days Ago	0.00	0.08	2.00	2.55
30 Days Ago	0.10	0.08	2.00	2.55
60 Days Ago	0.10	0.08	2.00	2.55
90 Days Ago	0.10	0.08	2.00	2.54

EPS Revisions	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Down Last 30 Days	0	0	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	EE	Industry	Sector	S&P 500
Current Qtr.	-100.00%	-10.50%	47.40%	2.90%
Next Qtr.	N/A	21.90%	49.80%	13.10%
This Year	-11.90%	13.00%	22.80%	2.60%
Next Year	27.50%	1.80%	8.00%	9.30%
Past 5 Years (per annum)	-2.74%	N/A	N/A	N/A
Next 5 Years (per annum)	7.00%	7.67%	6.15%	4.91%
Price/Earnings (avg. for comparison categories)	20.88	8.46	19.13	19.73
PEG Ratio (avg. for comparison categories)	2.98	3.67	3.29	1.98

Mon, Feb 8, 2016, 1:48PM EST - U.S. Markets close in 2 hrs 12 mins Report an Issue

Dow 2.

EDE

The Empire District Electric Company (EDE) - NYSE ★ Watchlist Like 10

27.75 0.96(3.34%) 1:47PM EST - NYSE Real Time Price

Analyst Estimates

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Earnings Est	Current Qtr. Mar 16	Next Qtr. Jun 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	0.35	0.20	1.50	1.61
No. of Analysts	1.00	1.00	5.00	5.00
Low Estimate	0.35	0.20	1.45	1.50
High Estimate	0.35	0.20	1.55	1.75
Year Ago EPS	0.34	0.15	1.29	1.50

Revenue Est	Current Qtr. Mar 16	Next Qtr. Jun 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	NaN	NaN	670.64M	691.86M
No. of Analysts			4	4
Low Estimate	NaN	NaN	655.76M	678.82M
High Estimate	NaN	NaN	678.10M	699.00M
Year Ago Sales	NaN	NaN	416.20M	670.64M
Sales Growth (year/est)	N/A	N/A	61.10%	3.20%

Earnings History	Mar 15	Jun 15	Sep 15	Dec 15
EPS Est	0.34	0.24	0.59	0.28
EPS Actual	0.34	0.15	0.58	0.23
Difference	0.00	-0.09	-0.01	-0.05
Surprise %	0.00%	-37.50%	-1.70%	-17.90%

EPS Trends	Current Qtr. Mar 16	Next Qtr. Jun 16	Current Year Dec 16	Next Year Dec 17
Current Estimate	0.35	0.20	1.50	1.61
7 Days Ago	N/A	N/A	1.51	1.61
30 Days Ago	N/A	N/A	1.52	1.61
60 Days Ago	N/A	N/A	1.51	1.61
90 Days Ago	N/A	N/A	1.50	1.60

EPS Revisions	Current Qtr. Mar 16	Next Qtr. Jun 16	Current Year Dec 16	Next Year Dec 17
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Down Last 30 Days	0	0	1	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	EDE	Industry	Sector	S&P 500
Current Qtr.	2.90%	38.80%	47.40%	2.90%
Next Qtr.	33.30%	241.20%	49.80%	13.10%
This Year	16.30%	12.10%	22.80%	2.60%
Next Year	7.30%	9.30%	8.00%	9.30%
Past 5 Years (per annum)	2.58%	N/A	N/A	N/A
Next 5 Years (per annum)	5.00%	6.80%	6.15%	4.91%
Price/Earnings (avg. for comparison categories)	19.14	22.50	19.13	19.73
PEG Ratio (avg. for comparison categories)	3.83	6.06	3.29	1.98

Currency in USD.

Eversource Energy (ES) - NYSE Watchlist

53.87 0.79(1.45%) 1:53PM EST - NYSE Real Time Price

Analyst Estimates

Earnings Est	Current Qtr. Mar 16	Next Qtr. Jun 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	0.93	0.61	3.01	3.21
No. of Analysts	8.00	8.00	18.00	17.00
Low Estimate	0.80	0.50	2.97	3.14
High Estimate	1.07	0.71	3.09	3.29
Year Ago EPS	0.81	0.66	2.81	3.01

Revenue Est	Current Qtr. Mar 16	Next Qtr. Jun 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	2.38B	1.76B	8.20B	8.42B
No. of Analysts	4	4	12	11
Low Estimate	2.19B	1.55B	7.68B	7.70B
High Estimate	2.60B	1.94B	8.61B	8.89B
Year Ago Sales	2.51B	1.87B	7.95B	8.20B
Sales Growth (year/est)	-5.20%	-5.70%	3.10%	2.60%

Earnings History	Mar 15	Jun 15	Sep 15	Dec 15
EPS Est	0.80	0.56	0.76	0.62
EPS Actual	0.81	0.66	0.75	0.60
Difference	0.01	0.10	-0.01	-0.02
Surprise %	1.30%	17.90%	-1.30%	-3.20%

EPS Trends	Current Qtr. Mar 16	Next Qtr. Jun 16	Current Year Dec 16	Next Year Dec 17
Current Estimate	0.93	0.61	3.01	3.21
7 Days Ago	0.93	0.61	3.01	3.21
30 Days Ago	0.92	0.60	3.02	3.21
60 Days Ago	0.89	0.62	3.03	3.22
90 Days Ago	0.88	0.61	3.04	3.22

EPS Revisions	Current Qtr. Mar 16	Next Qtr. Jun 16	Current Year Dec 16	Next Year Dec 17
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	2	1	1
Down Last 30 Days	0	0	1	1
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	ES	Industry	Sector	S&P 500
Current Qtr.	14.80%	-10.50%	47.40%	2.90%
Next Qtr.	-7.60%	21.90%	49.80%	13.10%
This Year	7.10%	13.00%	22.80%	2.60%
Next Year	6.60%	1.80%	8.00%	9.30%
Past 5 Years (per annum)	4.60%	N/A	N/A	N/A
Next 5 Years (per annum)	6.57%	7.67%	6.15%	4.91%
Price/Earnings (avg. for comparison categories)	18.16	8.46	19.13	19.73
PEG Ratio (avg. for comparison categories)	2.76	3.67	3.29	1.98

Currency in USD.

Great Plains Energy Incorporated (GXP) - NYSE ★ Watchlist

28.49 0.31(1.08%) 2:11PM EST - Nasdaq Real Time Price

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.17	0.16	1.40	1.75
No. of Analysts	8.00	4.00	13.00	13.00
Low Estimate	0.13	0.13	1.35	1.70
High Estimate	0.21	0.21	1.44	1.78
Year Ago EPS	0.12	0.12	1.57	1.40

Next Earnings Date: Feb 24, 2016 - Set a Reminder

Revenue Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	668.64M	593.04M	2.56B	2.69B
No. of Analysts	3	4	10	10
Low Estimate	581.64M	571.31M	2.45B	2.54B
High Estimate	723.27M	631.00M	2.66B	2.77B
Year Ago Sales	552.20M	549.10M	2.57B	2.56B
Sales Growth (year/est)	21.10%	8.00%	-0.20%	5.10%

Earnings History	Dec 14	Mar 15	Jun 15	Sep 15
EPS Est	0.13	0.11	0.30	0.88
EPS Actual	0.12	0.12	0.28	0.82
Difference	-0.01	0.01	-0.02	-0.06
Surprise %	-7.70%	9.10%	-6.70%	-6.80%

EPS Trends	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.17	0.16	1.40	1.75
7 Days Ago	0.17	0.16	1.40	1.75
30 Days Ago	0.19	0.16	1.40	1.75
60 Days Ago	0.19	0.16	1.40	1.76
90 Days Ago	0.19	0.18	1.45	1.80

EPS Revisions	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	2
Down Last 30 Days	0	0	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	GXP	Industry	Sector	S&P 500
Current Qtr.	41.70%	-10.50%	47.40%	2.90%
Next Qtr.	33.30%	21.90%	49.80%	13.10%
This Year	-10.80%	13.00%	22.80%	2.60%
Next Year	25.00%	1.80%	8.00%	9.30%
Past 5 Years (per annum)	23.23%	N/A	N/A	N/A
Next 5 Years (per annum)	5.07%	7.67%	6.15%	4.91%
Price/Earnings (avg. for comparison categories)	20.56	8.46	19.13	19.73
PEG Ratio (avg. for comparison categories)	4.06	3.67	3.29	1.98

Dow 2.39% Nasdaq 3.35%

IDA

IdaCorp, Inc. (IDA) - NYSE ★ Watchlist

Like 5

69.41 0.06(0.09%) 2:19PM EST - Nasdaq Real Time Price

Analyst Estimates

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Earnings Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.64	N/A	3.86	3.89
No. of Analysts	2.00	N/A	3.00	3.00
Low Estimate	0.61	N/A	3.84	3.85
High Estimate	0.66	N/A	3.90	3.92
Year Ago EPS	0.69	0.47	3.85	3.86

Next Earnings Date: Feb 18, 2016 - Set a Reminder

Revenue Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	NaN	NaN	1.27B	1.28B
No. of Analysts			2	2
Low Estimate	NaN	NaN	1.25B	1.26B
High Estimate	NaN	NaN	1.29B	1.30B
Year Ago Sales	NaN	NaN	1.28B	1.27B
Sales Growth (year/est)	N/A	N/A	-1.30%	1.40%

Earnings History	Dec 14	Mar 15	Jun 15	Sep 15
EPS Est	0.58	0.58	1.07	1.54
EPS Actual	0.69	0.47	1.31	1.46
Difference	0.11	-0.11	0.24	-0.08
Surprise %	19.00%	-19.00%	22.40%	-5.20%

EPS Trends	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.64	N/A	3.86	3.89
7 Days Ago	0.64	N/A	3.86	3.89
30 Days Ago	0.64	N/A	3.86	3.89
60 Days Ago	0.64	N/A	3.86	3.89
90 Days Ago	0.65	N/A	3.86	3.89

EPS Revisions	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	0	N/A	0	0
Up Last 30 Days	0	N/A	0	0
Down Last 30 Days	0	N/A	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	IDA	Industry	Sector	S&P 500
Current Qtr.	-7.20%	-10.50%	47.40%	2.90%
Next Qtr.	N/A	21.90%	49.80%	13.10%
This Year	0.30%	13.00%	22.80%	2.60%
Next Year	0.80%	1.80%	8.00%	9.30%
Past 5 Years (per annum)	13.17%	N/A	N/A	N/A
Next 5 Years (per annum)	4.00%	7.67%	6.15%	4.91%
Price/Earnings (avg. for comparison categories)	17.98	8.46	19.13	19.73
PEG Ratio (avg. for comparison categories)	4.50	3.67	3.29	1.98

Otter Tail Corporation (OTTR) - NasdaqGS ★ Watchlist

28.71 0.32(1.13%) 2:21PM EST - Nasdaq Real Time Price

Analyst Estimates

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Earnings Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.44	N/A	1.59	1.70
No. of Analysts	2.00	N/A	2.00	2.00
Low Estimate	0.42	N/A	1.57	1.70
High Estimate	0.45	N/A	1.60	1.70
Year Ago EPS	0.38	0.37	1.55	1.59

Next Earnings Date: Feb 8, 2016 - Set a Reminder

Revenue Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	203.75M	NaN	794.05M	838.00M
No. of Analysts	2		2	2
Low Estimate	198.20M	NaN	787.80M	822.90M
High Estimate	209.30M	NaN	800.30M	853.10M
Year Ago Sales	193.41M	NaN	799.26M	794.05M
Sales Growth (year/est)	5.30%	N/A	-0.70%	5.50%

Earnings History	Dec 14	Mar 15	Jun 15	Sep 15
EPS Est	0.45	0.55	0.23	0.44
EPS Actual	0.38	0.37	0.36	0.42
Difference	-0.07	-0.18	0.13	-0.02
Surprise %	-15.60%	-32.70%	56.50%	-4.50%

EPS Trends	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.44	N/A	1.59	1.70
7 Days Ago	0.44	0.59	1.59	1.70
30 Days Ago	0.48	0.59	1.63	1.72
60 Days Ago	0.48	0.59	1.63	1.72
90 Days Ago	0.48	0.59	1.63	1.72

EPS Revisions	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Down Last 30 Days	0	0	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	OTTR	Industry	Sector	S&P 500
Current Qtr.	15.80%	-10.50%	47.40%	2.90%
Next Qtr.	N/A	21.90%	49.80%	13.10%
This Year	2.60%	13.00%	22.80%	2.60%
Next Year	6.90%	1.80%	8.00%	9.30%
Past 5 Years (per annum)	33.38%	N/A	N/A	N/A
Next 5 Years (per annum)	6.00%	7.67%	6.15%	4.91%
Price/Earnings (avg. for comparison categories)	17.92	8.46	19.13	19.73
PEG Ratio (avg. for comparison categories)	2.99	3.67	3.29	1.98

PNW

Pinnacle West Capital Corporation (PNW) - NYSE ★ Watchlist

68.06 0.46(0.67%) 2:21PM EST - NYSE Real Time Price

Analyst Estimates

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Earnings Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.25	0.18	3.80	3.99
No. of Analysts	12.00	7.00	17.00	18.00
Low Estimate	0.15	0.11	3.76	3.90
High Estimate	0.31	0.25	3.85	4.07
Year Ago EPS	0.05	0.14	3.58	3.80

Next Earnings Date: Feb 19, 2016 - Set a Reminder

Revenue Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	763.01M	697.70M	3.53B	3.62B
No. of Analysts	5	5	12	12
Low Estimate	739.26M	682.00M	3.44B	3.51B
High Estimate	784.00M	714.20M	3.62B	3.76B
Year Ago Sales	726.45M	671.22M	3.49B	3.53B
Sales Growth (year/est)	5.00%	3.90%	1.10%	2.60%

Earnings History	Dec 14	Mar 15	Jun 15	Sep 15
EPS Est	0.18	0.18	1.23	2.32
EPS Actual	0.05	0.14	1.10	2.30
Difference	-0.13	-0.04	-0.13	-0.02
Surprise %	-72.20%	-22.20%	-10.60%	-0.90%

EPS Trends	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.25	0.18	3.80	3.99
7 Days Ago	0.25	0.18	3.80	4.00
30 Days Ago	0.23	0.19	3.79	4.01
60 Days Ago	0.23	0.19	3.79	4.01
90 Days Ago	0.23	0.19	3.79	4.01

EPS Revisions	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	1	0	1	0
Up Last 30 Days	4	0	3	0
Down Last 30 Days	0	0	1	1
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	PNW	Industry	Sector	S&P 500
Current Qtr.	400.00%	-10.50%	47.40%	2.90%
Next Qtr.	28.60%	21.90%	49.80%	13.10%
This Year	6.10%	13.00%	22.80%	2.60%
Next Year	5.00%	1.80%	8.00%	9.30%
Past 5 Years (per annum)	-0.04%	N/A	N/A	N/A
Next 5 Years (per annum)	4.95%	7.67%	6.15%	4.91%
Price/Earnings (avg. for comparison categories)	18.11	8.46	19.13	19.73
PEG Ratio (avg. for comparison categories)	3.66	3.67	3.29	1.98

PNM Resources, Inc. (PNM) - NYSE ★ Watchlist Like 7

32.10 0.04(0.11%) 2:22PM EST - Nasdaq Real Time Price

Analyst Estimates

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Earnings Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.18	0.22	1.59	1.63
No. of Analysts	7.00	1.00	9.00	9.00
Low Estimate	0.16	0.22	1.55	1.60
High Estimate	0.20	0.22	1.61	1.65
Year Ago EPS	0.24	0.21	1.49	1.59

Next Earnings Date: Feb 26, 2016 - Set a Reminder

Revenue Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	376.00M	350.00M	1.46B	1.50B
No. of Analysts	2	1	5	5
Low Estimate	370.00M	350.00M	1.45B	1.40B
High Estimate	382.00M	350.00M	1.48B	1.56B
Year Ago Sales	346.84M	332.87M	1.44B	1.46B
Sales Growth (year/est)	8.40%	5.10%	1.80%	2.50%

Earnings History	Dec 14	Mar 15	Jun 15	Sep 15
EPS Est	0.23	0.18	0.41	0.74
EPS Actual	0.24	0.21	0.44	0.76
Difference	0.01	0.03	0.03	0.02
Surprise %	4.30%	16.70%	7.30%	2.70%

EPS Trends	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.18	0.22	1.59	1.63
7 Days Ago	0.19	0.22	1.59	1.63
30 Days Ago	0.19	0.22	1.59	1.63
60 Days Ago	0.18	0.22	1.59	1.63
90 Days Ago	0.18	0.22	1.59	1.64

EPS Revisions	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Down Last 30 Days	0	0	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	PNM	Industry	Sector	S&P 500
Current Qtr.	-25.00%	-10.50%	47.40%	2.90%
Next Qtr.	4.80%	21.90%	49.80%	13.10%
This Year	6.70%	13.00%	22.80%	2.60%
Next Year	2.50%	1.80%	8.00%	9.30%
Past 5 Years (per annum)	14.59%	N/A	N/A	N/A
Next 5 Years (per annum)	9.30%	7.67%	6.15%	4.91%
Price/Earnings (avg. for comparison categories)	19.99	8.46	19.13	19.73
PEG Ratio (avg. for comparison categories)	2.15	3.67	3.29	1.98

Portland General Electric Company (POR) - NYSE ★ Watchlist Like 11

39.85 0.38(0.94%) 2:23PM EST - NYSE Real Time Price

Analyst Estimates

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Earnings Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.62	0.73	2.09	2.34
No. of Analysts	8.00	3.00	13.00	13.00
Low Estimate	0.57	0.63	2.02	2.27
High Estimate	0.66	0.86	2.12	2.40
Year Ago EPS	0.55	0.62	2.18	2.09

Next Earnings Date: Feb 12, 2016 - Set a Reminder

Revenue Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	544.39M	554.38M	1.95B	2.03B
No. of Analysts	5	3	11	11
Low Estimate	512.60M	473.04M	1.90B	1.95B
High Estimate	605.60M	682.13M	2.09B	2.18B
Year Ago Sales	500.00M	473.00M	1.90B	1.95B
Sales Growth (year/est)	8.90%	17.20%	2.80%	4.10%

Earnings History	Dec 14	Mar 15	Jun 15	Sep 15
EPS Est	0.52	0.70	0.41	0.48
EPS Actual	0.55	0.62	0.44	0.40
Difference	0.03	-0.08	0.03	-0.08
Surprise %	5.80%	-11.40%	7.30%	-16.70%

EPS Trends	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.62	0.73	2.09	2.34
7 Days Ago	0.62	0.73	2.09	2.34
30 Days Ago	0.63	0.75	2.10	2.34
60 Days Ago	0.63	0.75	2.10	2.34
90 Days Ago	0.63	0.74	2.10	2.34

EPS Revisions	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	1
Down Last 30 Days	0	0	0	1
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	POR	Industry	Sector	S&P 500
Current Qtr.	12.70%	-10.50%	47.40%	2.90%
Next Qtr.	17.70%	21.90%	49.80%	13.10%
This Year	-4.10%	13.00%	22.80%	2.60%
Next Year	12.00%	1.80%	8.00%	9.30%
Past 5 Years (per annum)	1.06%	N/A	N/A	N/A
Next 5 Years (per annum)	4.13%	7.67%	6.15%	4.91%
Price/Earnings (avg. for comparison categories)	19.09	8.46	19.13	19.73
PEG Ratio (avg. for comparison categories)	4.62	3.67	3.29	1.98

Westar Energy, Inc. (WR) - NYSE Watchlist

44.52 0.74(1.63%) 1:46PM EST - NYSE Real Time Price

Analyst Estimates

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Earnings Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.36	0.55	2.21	2.45
No. of Analysts	8.00	3.00	12.00	13.00
Low Estimate	0.28	0.47	2.09	2.38
High Estimate	0.41	0.65	2.25	2.55
Year Ago EPS	0.32	0.38	2.35	2.21

Next Earnings Date: Feb 24, 2016 - Set a Reminder

Revenue Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	639.79M	644.23M	2.56B	2.68B
No. of Analysts	3	4	10	10
Low Estimate	596.50M	627.70M	2.43B	2.52B
High Estimate	720.14M	665.57M	2.65B	2.82B
Year Ago Sales	596.44M	590.81M	2.60B	2.56B
Sales Growth (year/est)	7.30%	9.00%	-1.40%	4.60%

Earnings History	Dec 14	Mar 15	Jun 15	Sep 15
EPS Est	0.35	0.43	0.42	1.03
EPS Actual	0.32	0.38	0.46	0.97
Difference	-0.03	-0.05	0.04	-0.06
Surprise %	-8.60%	-11.60%	9.50%	-5.80%

EPS Trends	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.36	0.55	2.21	2.45
7 Days Ago	0.36	0.55	2.21	2.45
30 Days Ago	0.37	0.55	2.21	2.45
60 Days Ago	0.38	0.51	2.22	2.45
90 Days Ago	0.38	0.51	2.22	2.44

EPS Revisions	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	1
Down Last 30 Days	0	0	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	WR	Industry	Sector	S&P 500
Current Qtr.	12.50%	-10.50%	47.40%	2.90%
Next Qtr.	44.70%	21.90%	49.80%	13.10%
This Year	-6.00%	13.00%	22.80%	2.60%
Next Year	10.90%	1.80%	8.00%	9.30%
Past 5 Years (per annum)	17.44%	N/A	N/A	N/A
Next 5 Years (per annum)	3.50%	7.67%	6.15%	4.91%
Price/Earnings (avg. for comparison categories)	20.48	8.46	19.13	19.73
PEG Ratio (avg. for comparison categories)	5.85	3.67	3.29	1.98

UNS ELECTRIC, INC.

DOCKET NO. E-04204A-15-0142

SURREBUTTAL TESTIMONY

OF

JEFFREY MICHLIK

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

FEBRUARY 23, 2016

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ATTACHMENTS

Selected Company response to RUCO's data request .... Attachment A
Staff and the Company's agreement on revenue requirement .... Attachment B
Surrebuttal Schedules .... Attachment C

EXECUTIVE SUMMARY - SURREBUTTAL

The Residential Utility Consumer Office ("RUCO") has reviewed the rebuttal testimony of UNS Electric, Inc. ("Company or UNS"), and the direct testimony of Commission Staff ("Staff") and the various interveners in this docket.

The following are the Company's and RUCO's proposed rate base and adjusted operating income positions as filed in its direct, rebuttal, and surrebuttal testimonies.

Rate Base in Thousands of Dollars

Company Direct	Company Rebuttal	RUCO Direct	RUCO Surrebuttal
$355,720	$353,891	$345,131	$353,755

Adjusted Operating Income in Thousands of Dollars

Company Direct	Company Rebuttal	RUCO Direct	RUCO Surrebuttal
$8,044	$8,434	$10,517	$8,673

The following tables present the required gross revenue increase as filed by the Company and RUCO in their direct, rebuttal, and surrebuttal testimonies.

Required Dollar Increase in Gross Revenues in Thousands of Dollars

Company Direct	Company Rebuttal	RUCO Direct	RUCO Surrebuttal
$22,621	$18,457	$12,271	$17,206

Required Percentage Increase in Gross Revenues

Company Direct	Company Rebuttal	RUCO Direct	RUCO Surrebuttal
15.9%	11.78%	8.07%	10.84%

Return on Equity

Company Direct	Company Rebuttal	RUCO Direct	RUCO Surrebuttal
10.35%	9.50%	8.16%	9.13%

I. INTRODUCTION

Q. Please state your name for the record.

A. My name is Jeffrey M. Michlik.

Q. Have you previously filed testimony regarding this docket?

A. Yes, I have. I filed direct testimony in this docket on November 6, 2015.

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony will address the Company rebuttal positions and Staff's positions on revenue requirement issues.

Q. How is your surrebuttal testimony organized?

A. My surrebuttal testimony is presented in four sections. Section I provides an introduction. Section II addresses surrebuttal rate base adjustments. Section III addresses surrebuttal operating adjustments, and Section IV addresses other issues.

Q. Did the Company in its rebuttal testimony provide updated rebuttal schedules?

A. No, the Company did not provide a completed set of updated rebuttal schedules, only G and H schedules.

Q. In the Company's rebuttal testimony did the Company state what they were requesting as an updated revenue requirement?

A. Yes, the Company stated that they are in agreement with Staff's revenue requirement of $18.5 million.[1]

Q. Did the Company also state that they were in agreement with most of Staff's revenue requirement adjustments?

A. Yes.[2]

Q. Did RUCO ask the Company to provide updated rebuttal schedules?

A. Yes, in RUCO data request 11.6.

Q. What was the Company's response?

A. The Company provided an excel version of its revenue requirement model. However, it is unclear whether the updated numbers were confidential or not.

Q. Did RUCO ask the Company if it could use the numbers from the excel sheet to update the Company's position?

A. Yes.

[1] See the Rebuttal Testimony of David J. Lewis, page 6, line 17.
[2] Ibid. page 1, line 18.

Q. Did RUCO update its schedules and in the executive summary to reflect the Company's rebuttal position?

A. Yes. In addition, RUCO removed several of its adjustments as they were the same or similar to Staff's adjustments as will be explained later.

Q. Are there any corrections you would like to make at this time?

A. Yes, as will be discussed later, RUCO is revising its operating adjustment number no. 1 Base Fuel Costs.

II. SURREBUTTAL RATE BASE ADJUSTMENTS

Q. Did the Company specifically state in its rebuttal testimony which Staff rate base adjustments it was willing to accept?

A. No. However, they did provide an Exhibit to the testimony of Company witness David J. Lewis. It should be noted that page two of this exhibit is missing from docket control. Please see attachment B for a full copy of Staff and the Company's agreement.

Q. Can you please identify the rate base adjustments along with the dollar amounts that both the Company and Staff have agreed on, and RUCO is willing to accept?

A. Yes.

Gila River Adjustment

The Company and Staff agree to reduce rate base by $2,000,000 related to depreciation expense as deferred by the accounting order for Gila River.

Director and Officers (D&O) Prepaid Insurance

The Company and Staff agree to reduce D&O prepaid Insurance by 50 percent ($16,778).

Q. Did you address RUCO's adjustment to Net Operating Loss Carryforwards in your direct testimony?

A. Yes. However, based on the Internal Revenue Service issuance of two additional Private Letter Rulings that support the Company's position, RUCO has withdrawn its adjustment.

Q. Has RUCO revised its schedules to reflect these adjustments?

A. Yes.

Q. Do you have any additional comments?

A. No.

III. SURREBUTTAL OPERATING INCOME ADJUSTMENTS

Q. Did the Company specifically state in its rebuttal testimony which Staff operating income adjustments it was willing to accept?

A. No. However, they did provide an Exhibit to the testimony of Company witness David J. Lewis. It should be noted that page two of this exhibit is missing from docket control. Please see attachment B for a full copy of Staff and the Company's agreement.

Q. Can you please identify the operating income adjustments along with the dollar amounts that both the Company and Staff have agreed on, and RUCO is willing to accept?

A. Yes.

Incentive Compensation

The Company and Staff have agreed to a 50/50 sharing of incentive compensation which results in an operating income adjustment of ($14,611).

Bad Debt Expense

The Company and Staff have agreed on Bad Debt Expense which results in an operating adjustment of $489,791. In addition, $450,000 of bad debt expense relating to the mine company filing for bankruptcy has been removed resulting in a decrease in the Gross Revenue Conversion Factor.

Injuries and Damages

The Company has removed the $1,000,000 insurance claim which results in an operating income adjustment of $40,376.

Directors and Officer ("D&O") Expenses

The Company and Staff have agreed to a 50/50 sharing of D&O expenses which results in an operating income adjustment of $20,028.

OATT

The Company and Staff have agreed to an OATT amount of $14,511,531 which results in an operating income adjustment of ($12,431).

BASE FUEL RATES

Q. Based on additional information gathered from the Company during the discovery process, has RUCO revised its operating adjustment to No. 1 base fuel costs?

A. Yes. Initially this was complicated by the Company's H-3 filings in which the present base fuel rates were the same as the Company's proposed base fuel rates. Frankly, RUCO was unclear on what the Company meant by rebalancing its fuel costs in a prior data request. In a follow-up data request RUCO 8.1 (see Attachment A), the Company stated that "UNS Electric proposed base cost of fuel of $.048427 per kWh. This results in total expenses of $77,522,386 based on test-year adjusted retail sales of 1,600,809,167 kWh. The $14,869,928 reduction to Fuel costs is necessary in order to reflect the average cost of fuel and purchase power at 4.8427 cent/kWh." Therefore, the base fuel rate was also reduced and allocated to the different customer classes.

Q. Has the Company revised its H-3 schedules in rebuttal testimony to reflect the Commission approved present rates?

A. Yes. See Exhibit CAJ-R-4 of Company witness Craig A. Jones.

Q. Does RUCO agree with the Company's updated proposed base cost of fuel of $.053288 per kWh, which is the same as Staff recommended in its direct testimony?

A. No. The Company relies on Staff's calculation which uses eight months of actual costs from January through August 2015, and the Company's forecasted costs for September through December 2015. The forecasted costs were not known and measureable at the time.

Q. Did RUCO ask the Company for an updated base fuel cost which is based on known and measureable costs?

A. Yes. The Company in response to RUCO data request 10.5 stated "UNS Electric's 2015 average fuel and purchase power rate was $0.053689 per kWh. This was based on 2015 actual fuel and purchase power costs of $87,301,407 and retail sales of 1,626,067,036 kWh."

Q. Has RUCO revised its adjustment to reflect this information?

A. Yes. RUCO has updated the forecasted costs for September through December 2015 with actual costs provided by the Company, see RUCO Surrebuttal Schedule JMM-6.

SHORT-TERM INCENTIVE COMPENSATION

Q. Did you address RUCO's adjustment to short-term incentive compensation in your direct testimony?

A. Yes.

Q. Do you have any additional comments?

A. Other than Decision No. 75268, cited on page 5, line 2 of Company witness Lewis' rebuttal testimony, historically the Commission has not allowed incentive compensation to be borne 100 percent by ratepayers.

Decision No. 68487 (dated February 23, 2006) - "In Decision No. 64172, the Commission adopted Staff's recommendation regarding MIP expenses based on Staffs claim that two of the five performance goals were tied to return on equity and thus primarily benefited shareholders. We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Although achievement of the performance goals in the MIP, and the benefits attendant thereto, cannot be precisely quantified, there is little doubt that both shareholders and ratepayers derive some benefit from incentive goals. Therefore, the costs of the program should be borne by both groups and we find Staff's equal sharing recommendation to be a reasonable resolution."[3]

Decision No. 70011 (dated November 27, 2007) – "We believe that Staff's recommendation provides a reasonable balancing of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program. As RUCO points out, the program is comprised of elements that relate to the parent company's financial performance and cost containment goals, matters that primarily benefit shareholders."[4]

Decision No. 70360 (dated May 27, 2008) – "Consistent with our finding in the UNS Gas rate case (Decision No. 7001 1. at 26-27), we believe that Staff's recommendation provides a reasonable balancing of the interests

[3] See page, 18 line 4 of Decision No. 68487.
[4] See page, 27 line 1 of Decision No. 70011.

between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program."[5]

Decision No. 70665 (dated December 24, 2008) – "In the last Southwest Gas rate case, as well as several subsequent cases we disallowed 50 percent of management incentive compensation on the basis that such programs provide approximately equal benefits to shareholders and ratepayers because the performance goals relate to Financial performance and cost containment goals as well as customer service elements. (Decision Vo. 68487 at 18.) In that Decision, we stated: In Decision No. 64 172, the Commission adopted Staff's recommendation regarding MIP expenses based on Staff's claim that two of the five performance goals were tied to return on equity and thus primarily benefited shareholders. We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Although achievement of the performance goals in the MIP, and the benefits attendant thereto, cannot be precisely quantified, there is little doubt that both shareholders and ratepayers derive some benefit from incentive goals. Therefore, the costs of the program should be borne by both groups and we find Staffs equal sharing recommendation to be a reasonable resolution. (Id.) We believe the same rationale exists in this case to adopt the position advocated by Staff and RUCO to disallow 50 percent of the Company's proposed MIP costs."[6]

[5] See page, 21 line 1 of Decision No. 70360.
[6] See page, 16 line 3 of Decision No. 70665.

Decision No. 71914 (dated September 30, 2010) – "We believe that the Staff and RUCO recommendations, to require a 50/50 sharing of incentive, compensation costs, provide a reasonable balancing of the interests between ratepayers and shareholders. The equal sharing of such costs recognizes that the program is comprised of elements that relate to the parent company's financial performance and cost-containment goals, matters that primarily benefit shareholders, while at the same time recognizing that a portion of the program's incentive compensation is based on meeting customer service goals. This offers the opportunity for the Company's customers to benefit from improved performance in that area."[7] Further, in some rate cases performance pay or bonus pay has been completely disallowed by the Commission.

Decision No. 71865 (dated August 31, 2010) – "We agree with Staff that the performance pay, or bonus pay, should not be included as part of expenses included in rates."[8]

Decision No. 74568 (dated June 20, 2014) – "We agree with Staff that the Company failed to quantify or justify its proposed recovery of incentive pay, and disagree with RUCO that half of the incentive pay request should be allowed."[9]

[7] See page, 28 line 19 of Decision No. 71914.
[8] See page, 27 line 8 of Decision No. 71865.
[9] See page, 25 line 14 of Decision No. 74568.

RATE CASE EXPENSE

Q. Did you address RUCO's adjustment to rate case expense in your direct testimony?

A. Yes.

Q. Do you have any additional comments?

A. Just a few.

Q. The Company states in surrebuttal testimony that outside consulting services are expected to increase. Further, these costs are the incremental real cost associated with filing this case and should be fully recoverable. Please respond?

A. First, the Company always has the discretion on who it contracts as outside witnesses. The Company has hired another consultant H. Edwin Overcast to reiterate what Company witnesses Dukes and Jones have already stated in both their direct and rebuttal testimonies regarding the Company's three part rate design.

Q. Are you saying the Company cannot hire additional witnesses or attorneys?

A. No. They can hire as many attorney's or expert witnesses as they want, but at some point the services become duplicative, and ratepayers should not bear the extra costs. In addition, allowing utility companies more in rate case expense will only encourage this type of behavior.

Q. Has RUCO revised its schedules to reflect these adjustments?

A. Yes.

IV. OTHER ISSUES

ARIZONA PROPERTY TAX DEFERRAL

Q. Did you address the Company's Arizona Property Tax Deferral in your direct testimony?

A. Yes.

Q. Do you have any additional comments?

A. No.

GILA RIVER PROPERTY TAX DEFERRAL

Q. Did you address the Company's Gila River Property Tax Deferral in your direct testimony?

A. Yes.

Q. Do you have any additional comments?

A. Yes.

Q. In your direct testimony you stated RUCO could support a 50/50 sharing of and deferral of legal costs up to a certain limit; costs that the *Company would not ordinarily be able to recover*, in order for the Company to litigate in Arizona Tax Court against the Arizona Department of Revenue?

A. Yes.

Q. Why is that?

A. The Gila River Power Plant was a good acquisition for ratepayers. The Company only asked for a deferral of 25 percent of its costs. In addition, the Company could not defer more cost than its deferred savings. The Company also only asked for a 5.00 percent carrying cost. These benefits are just a few of the benefits identified, so RUCO sees this as an extension of the acquisition.

Q. Is RUCO's recommended 50/50 sharing of legal costs only applicable to this case and to the Gila River Property Tax deferral?

A. Yes. Unfortunately, one can argue all types of legal fees incurred outside a rate case should be deferred and are extraordinary, which would set a bad precedent going-forward.

Q. How does this benefit the Company and Shareholders in the long-run?

A. The Company is able to reduce its expenses, recover 50 percent of legal fees it would ordinary not recover, and as a result of properly managing its expenses increases its credit ratings and as a result increases shareholders value in the Company.

Q. Has the Company provided any additional information in their rebuttal filing?

A. Yes. Company Witness Mr. Rademacher states on page 9. Line 11 of his testimony:

"Q. What factors should the Commission be aware of that will mitigate costs?

A. UNS Electric is not the first to litigate Gila River property tax values with the ADOR. Sun Devil Holdings, the owners of Gila River Block 1 & 2, are already in Tax Court litigating the same exact issue UNS Electric plans to litigate.

Q. How does the Sun Devil litigation mitigate UNS Electric's costs?

A. If Sun Devil wins its case, the Tax Court should not need to devote as much effort to hearing interpretations of statutes from UNS Electric and the ADOR. Precedent will have been set and UNS Electric's focus would be on proving that its facts are the same as Sun Devil's. If Sun Devil loses, UNS Electric has the opportunity to drop its case and avoid further litigation costs."

Q. Has RUCO asked the Company in a Data Request, how much the Company has incurred in legal expenses to date regarding their tax case against the Arizona Department of Revenue?

A. Yes. However, that information is subject to a confidentiality agreement. The Company did state that it has "filed its complaint with the Tax Court and is awaiting the answer from the Defendants, which we expect in February 2016. The Company is in the pre-discovery stage of the legal proceedings."

Q. Does your silence on any of the issues, matters or findings addressed in the testimony of any of the witnesses for the Company constitute your acceptance of their positions on such issues, matters or findings?

A. No. RUCO limited its discussion to the specific issues outlined above. RUCO's lack of response to any issue in this proceeding should not be construed as agreement with the Company's position in its rebuttal testimony; rather, where there is no response, RUCO relies on its original direct testimony.

Q. Does this conclude your rebuttal testimony?

A. Yes.

ATTACHMENT A

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S EIGHTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
December 14, 2015

RUCO 8.1

Base Power Charges – This is a follow-up data request to RUCO 4.12 which asked the questions why the Company used its proposed rates to calculate its adjusted test year revenues in relation to base fuel rates:

The Company responded by stating:

There are four key steps in the Company filed revenue proof: 1) test year revenues; 2) adjusted revenues; 3) adjusted revenues with the rebalance of fuel cost (proposed fuel rates); and 4) final revenues (proposed rates with rebalance of fuel cost – new fuel rates). The tab "TY Revenue Proof" demonstrates step one and two, whereas the tab "Final Revenue Proof" completes steps three and four. Since the average cost of fuel is reset in the case, the Company felt it was important to show this third interim step between adjusted revenues and proposed rates which shows current rates with new fuel rates. This is why all fuel rates for step three and four are the same. The comparison of adjusted test-year revenues to proposed are simply between step two and four. Both test-year and adjusted revenues and the bill impacts use current rates for calculating current revenues and current bill impacts

Please answer the following questions:

a. Did the Company adjust the overall revenue related to base fuel to $77,522,386?

b. On the Company's Cost of Service Study, tab G-6 are the Function Expenses comprised of the following costs for energy?

547 PPFAC-Fuel	$ 5,543,690
555 PPFAC-Energy	$62,964,670
565 Transmission of Electricity	$ 9,014,026
Total	$77,522,386

c. Did the Company reduced the following expense accounts in the test year?

547 PPFAC-Fuel	$ 1,028,693
555 PPFAC-Energy	$12,168,583
565 Transmission of Electricity	$ 1,672,652
Total	$14,869,928

d. Does the $14,869,928 tie to the Company's 2015 UNSE Revenue Proof-Public Version, Summary tab, Cell M46?

e. Did the Company calculate the $14,869,928 adjustment as follows?

Test Year Adjusted Billing Determinants	1,600,809,167	(A)
Proposed PPFAC Rate	0.048427	(C)
Calculated New Fuel	77,522,385.53	
Test Year Proposed PPFAC Revenue	92,392,313	(B)
PPFAC Adjustment	(14,869,928)	

Source:
(A) 2015 UNSE Revenue Proof/Summary/Test Year Adjusted Sales (kWh)
(B) 2015 UNSE Revenue Proof/Summary/Test Year Adjusted Fuel Revenue
(C) M. Sheehan PPFAC Forecast - average June 2016 - May 2017

f. How is the proposed PPFAC rate known and measureable if the PPFAC is based on an average from June 2016 – May 2017?

g. Please provide a copy of Mr. Sheehan's forecast if not already provided, if already provided please provide a bates number or reference.

h. Based on the following table presented below, were the current rates authorized by the Commission in Column [A] changed by the Company in Column [D] to represent the Company's current rates after its quote "rebalancing of base fuel rates", based on Mr. Sheehan's forecast?

		[A]	[B]	[C] = [A] * [B]	[D]	[E]	[F] = [D] * [E]	[G]
LINE NO.	RATE SCHEDULE	COMMISSION AUTHORIZED CURRENT RATES	ADJUSTED BILLING DETERMINANTS	TEST YEAR ADJUSTED REVENUE	COMPANY CURRENT RATES	ADJUSTED BILLING DETERMINANTS	TEST YEAR ADJUSTED REVENUE	Company Adjustment to Test Year Revenue
1	**Residential Service**							
2	Base Power	$ 0.06451	761,215,400	$ 49,106,005	$ 0.04926	761,215,400	$ 37,497,471	$ 11,608,535
3								
4	**Cares Residential**							
5	Base Power	$ 0.06170	58,840,325	$ 3,630,448	$ 0.04926	58,840,325	$ 2,898,474	$ 731,974
6								
7	**Residential TOU**							
8	Summer On-peak	$ 0.1296	411,735	$ 53,363	$ 0.1011	411,735	$ 41,631	$ 11,732
9	Summer Off-peak	$ 0.0396	1,412,262	$ 55,933	$ 0.0339	1,412,262	$ 47,876	$ 8,057
10	Winter On-peak	$ 0.1296	299,937	$ 38,873	$ 0.0990	299,937	$ 29,682	$ 9,192
11	Winter Off-peak	$ 0.0314	928,930	$ 29,154	$ 0.0336	928,930	$ 31,193	$ (2,038)
12								
13	**Residential TOU - Super Peak**							
14	Summer On-peak	$ 0.1700	0	$ -	$ 0.1497	0	$ -	$ -
15	Summer Off-peak	$ 0.0397	0	$ -	$ 0.0383	0	$ -	$ -
16	Winter On-peak	$ 0.1500	78	$ 12	$ 0.1497	78	$ 12	$ 0
17	Winter Off-peak	$ 0.0387	186	$ 7	$ 0.0383	186	$ 7	$ 0
18								
19	**Residential Bright Community Solar**							
20	Total Fuel Revenue	$ 0.0845	634,848	$ 53,651	$ 0.0845	634,848	$ 53,651	$ -
21								
22	**Small General Service**	$ 0.0582	118,501,366	$ 6,901,638	$ 0.0486	118,501,366	$ 5,760,351	$ 1,141,287
23								
24	**Small General Service TOU**							
25	Summer On-peak	$ 0.1296	10,833	$ 1,404	$ 0.1265	10,833	$ 1,371	$ 34
26	Summer Off-peak	$ 0.0396	93,049	$ 3,685	$ 0.0330	93,049	$ 3,072	$ 614
27	Winter On-peak	$ 0.1296	15,595	$ 2,021	$ 0.1085	15,595	$ 1,692	$ 329
28	Winter Off-peak	$ 0.0314	62,953	$ 1,976	$ 0.0329	62,953	$ 2,072	$ (96)
29								
30	**Interuptible Power Service**							
31	Base Power	$ 0.0438	35,567,841	$ 1,556,449	$ 0.0498	35,567,841	$ 1,772,015	$ (215,567)
32								
33	**Medium General Service**							
34	Base Power	$ 0.0566	445,782,493	$ 25,232,626	$ 0.0484	445,782,493	$ 21,593,704	$ 3,638,922
35								
36	**Medium General Service TOU**							
37	Summer On-peak	$ 0.1149	728,854	$ 83,735	$ 0.1099	728,854	$ 80,101	$ 3,634
38	Summer Off-peak	$ 0.0399	2,959,583	$ 118,046	$ 0.0335	2,959,583	$ 99,146	$ 18,900
39	Winter On-peak	$ 0.1149	907,877	$ 104,302	$ 0.0899	907,877	$ 81,618	$ 22,684
40	Winter Off-peak	$ 0.0262	3,122,643	$ 81,713	$ 0.0316	3,122,643	$ 98,676	$ (16,962)
41								
42	**Large Power Service 3>69kV**							
43	Base Power	$ 0.0419	58,092,107	$ 2,432,897	$ 0.0484	58,092,107	$ 2,811,658	$ (378,761)
44								
45	**Large General Service TOU (Formally LPS 3 TOU<69KV**							
46	Summer On-peak	$ 0.1236	1,259,777	$ 155,683	$ 0.1455	1,259,777	$ 183,310	$ (27,627)
47	Summer Off-peak	$ 0.0247	6,623,822	$ 163,714	$ 0.0345	6,623,822	$ 228,588	$ (64,874)
48	Winter On-peak	$ 0.0939	1,200,529	$ 112,706	$ 0.1245	1,200,529	$ 149,478	$ (36,772)
49	Winter Off-peak	$ 0.0221	6,334,135	$ 140,016	$ 0.0329	6,334,135	$ 208,456	$ (68,440)
50								
51	**Large Power Service 3>69kV**							
52	Base Power	$ 0.04188	86,421,524	$ 3,619,333	$ 0.04841	86,421,524	$ 4,183,666	$ (564,333)
53								
54								
55	**Dusk To Dawn**							
56	Base Power	$ 0.0101	2,827,250	$ 28,592	$ 0.0131	2,827,250	$ 37,065	$ (8,473)
57								
58							$ 77,896,035	$ 15,811,950
59								
60					Less: Cares		$ (372,156)	
61					Plus: Residential			
62					Less: Medium/Large		$ (1,807,790)	
63					Service Migration			
64					Plus: Large Power		$ 1,806,298	
65					Customer migration			
66					Other Fuel Adjustments PPFAC			$ (30,681,878)
67							$ 77,522,386	$ (14,869,928)

i. Please provide a brief narrative on how the $14,869,928 adjustment was allocated to each customer class (i.e. residential, small generating, large power service, etc.)? In your response include any spreadsheet or calculations to support the Company's allocation.

j. Please provide a brief narrative on how each base fuel rate was adjusted (i.e. residential

.06451 to .04926)? In your response include any spreadsheet or work papers to support your calculation.

k. When did the Company first start using this methodology?

l. Please cite the Commission Decision that authorized this methodology, and provide a copy of the decision with the specific reference to the Commission's adoption of this methodology. In addition, please state whether the case was fully litigated or a result of a settlement agreement.

m. Why is Staff's recommended base fuel cost of $0.053288 per kWh, and total expense of $85,303,919, based on retail sales of 1,600,809,167 kWh unreasonable?

n. Please provide a random sample of five customer bills for the month of October 2015 for each customer class, with names and addresses redacted.

o. Please provide a random sample of five solar customer bills for the month of October, with names and addresses redacted. Please mark as solar customers.

RESPONSE:

a. Yes, UNS Electric proposed base cost of fuel of $.048427 per kWh. This results in a total expenses of $77,522,386 based on test-year adjusted retail sales of 1,600,809,167 kWh.

b. Yes.

c. Yes. The $14,869,928 reduction to Fuel costs is necessary in order to reflect the average cost of fuel and purchase power at 4.8427 cent/kWh.

d. Yes.

e. Yes.

f. Fuel, purchased power and purchased transmission cost are presently reconcilable through the Commission approved PPFAC process. Prior to Commission Decision No. 74235 (December 31, 2013), UNS Electric was forecasting these PPFAC expenses in advance of incurring them, billing the rates based off the estimate for a year and then truing up any over or under recovery the subsequent year. Therefore, fuel recovery rates were being established and approved by the Commission based upon estimates of sales and cost for the effective period of the PPFAC rates (this is presently still the practice at TEP).

In the present proceeding UNS Electric is establishing the base fuel rates that will be charged to customers in the second half of 2016 - then adjusted monthly based on actual cost (UNS Electric only recovers the actual cost incurred). As such, UNS Electric believes it is appropriate to establish the base fuel rates as closely as possible to expected levels; including the full operation of Gila River, to mitigate true-up or reconciling adjustments.

g. **THE FILE LISTED BELOW CONTAINS CONFIDENTIAL INFORMATION AND IS BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.**

Please see RUCO 8.1g UNSE April16-March17 Forecast-Confidential.xlsx.

h. No. The rates represented in your table as column D include the Company's proposed fuel rates. The revenue proof (public version) tab TY Revenue Proof columns C – E shows the test-year revenues based on current rates. The same tab, columns G – I show the test year adjustments for customer and weather normalization based on current rates. As shown in your table the Commission authorized current base power rate for the residential class is $0.064510. This same rate was used to calculate the test-year base fuel revenues and adjusted test-year base fuel revenues for residential (see column C, row 16 and column H, row 16 in the TY Revenue Proof tab). Below, please see the snapshot of Residential TY revenues and TY Adjusted Revenues calculated based on current Commission approved rates.

UNS ELECTRIC INC.
TEST PERIOD ENDING DECEMBER 31, 2014
REVENUE PROOF

Rate Schedule	Current Rates	Test Year Billing Determinants	Test Year Billed Revenues	Adjusted Billing Determinants	Current Rates	Adjusted TY Revenue
5703 RESIDENTIAL SERVICE						
Basic Service Charge	$10.00	910,158	$9,101,580	912,420	$10.00	$9,124,200
Energy Charge 1st 400 kWh	$0.019300	306,169,110	5,909,064	305,205,763	$0.019300	5,890,471
Energy Charges 401 - 1,000 kWh	$0.034350	265,903,606	9,133,789	265,302,752	$0.034350	9,113,150
Energy Charge, all additional kWh	$0.038499	182,932,901	7,042,734	190,706,885	$0.038499	7,342,024
TCA, per kWh	$0.001140	502,144,901	572,445	502,144,901	$0.001140	572,445
Margin Total			$31,759,612			$32,042,290
Base Power	$0.064510	755,005,617	$48,705,412	761,215,400	$0.064510	$49,106,005
PPFAC Revenue	Varies by Month		(1,705,692)		Varies by Month	(1,724,767)
Total Fuel Revenue			$46,999,721			$47,381,239
Total Residential Revenue			$78,759,332			$79,423,529

In the public revenue proof tab Final Revenue Proof the company is showing the proposed fuel rates in Column C (which was incorrectly labeled as Current Rates) and uses the proposed rates in column J. See the snapshot of residential information below.

UNS ELECTRIC INC.
TEST PERIOD ENDING DECEMBER 31, 2014
FINAL REVENUE PROOF

LINE NO.	RATE SCHEDULE	CURRENT RATES/Proposed Fuel Rates	ADJUSTED BILLING DETERMINANTS	TEST YEAR ADJUSTED REVENUE	NEW BILLING DETERMINANTS	PROPOSED RATES	PROPOSED REVENUES
	RESIDENTIAL SERVICE						
1	Basic Service Charge	$10.00	912,420	$9,124,200		$20.00	$18,248,400
2	0-400	$0.019300	305,205,763	5,890,471		$0.030810	9,403,390
2	401-1,000	$0.034350	265,302,752	9,113,150		$0.050810	13,480,033
3	Over 1,000	$0.038499	190,706,885	7,342,024		$0.050810	9,689,817
3	TCA, per kWh	$0.001140	0	0		$0.000000	0
4	**Margin Total**			$31,469,845			$50,821,639
5	Base Power	$0.049260	761,215,400	$37,497,471		$0.049260	$37,497,471
6	PPFAC Revenue	Varies by Month	0	0			0
7	**Total Fuel Revenue**			$37,497,471			$37,497,471
8	**Total Residential Revenue**			$68,967,316			$88,319,110

The interim step was to provide a test-year adjusted revenue proof that tied to the ACC Adjusted test-year retail revenue presented in Schedule C-1, page 1 of 1.

i. Adjustments to base power was done in conjunction with the adjustments to non-fuel rates. The adjustments were made with two primary goals in mind: 1) levelizing the base power cost between rate classes, and 2) bill impact. Overall, there is one average cost of purchased power and fuel for the system. Except for specific instances where cost differentials can be more easily justified, such as Time-of-use rates, interruptible rates, and transmission level services, large differentials in base power costs should be reduced in the Company's opinion. In this case the Company has moved the base power amounts closer to the average cost in most classes. Bill impact must also be considered; therefore, the combination of "re-alignment" of base power and non-fuel increases had to be considered as new rates were designed. The Company believes a fair and equitable set of proposed rates was the result of these efforts. There was no specific allocation of the $14.8 million between classes to arrive at the rates. Instead the rates were calculated using the described theory to create a more equitable base power cost between the classes and the distribution of total base power cost resulting from these recalculations generated the total base power cost reflected in the revenue proof, by class.

j. Please refer to the response to RUCO 8.01 (i) above.

k. There is no specific "methodology" being used other than the simple application of the theory of proposing rates reflective of equitable cost allocation. This is a primary goal of the Company in this case, while still considering overall bill impact.

l. As discussed above, this is not a specific "methodology". It is a goal being proposed in this proceeding and part of the Company's overall request for fair and equitable rates. Fair and equitable rates are the goal of all Commission Decisions. The rates being proposed by the Company in this proceeding are just another way of getting there.

m. The Company has not made a determination yet as to the reasonableness of Staff's proposed average base fuel rate.

n. Please see RUCO 8.1n.pdf, Bates Nos. UNSE\015041-015060, for the requested sample bills.

o. Please see RUCO 8.1o.pdf, Bates Nos. UNSE\015061-015065, for the requested sample bills.

RESPONDENT:

David Lewis (a, c, e) / Brenda Pries (b, d, h, n, o) / Dallas Dukes (f, m) / Michael Sheehan (g) /

Craig Jones (i, j, k, l)

WITNESS:

David Lewis (a, c, e) / Craig Jones (b, d, h, i, j, k, l, n, o) / Dallas Dukes (f, m) /

Michael Sheehan (g)

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S TENTH SET OF DATA REQUESTS
REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
January 18, 2016

RUCO 10.5

UNSE Base Fuel Cost – In regards to UNSE base fuel costs, please answer the following question:

a. Please provide the base fuel costs in KWh from the period January through December 2015, in total and by month.

This should approximate Staff's calculated base fuel cost of $0.053288 per KWh which used actual costs from January through August 2015, and UNSE's forecasted costs for September through December 2015. To clarify please adjust Staff's calculation of base fuel costs to account for actual costs from September through December 2015.

RESPONSE:

Please see RUCO 10.5 - UNSE 2015 Fuel and Purchase Power Costs.xlsx. Using Staff's calculation methodology, UNS Electric's 2015 average fuel and purchase power rate was $0.053689 per kWh. This was based on 2015 actual fuel and purchase power costs of $87,301,407 and retail sales of 1,626,067,036 kWh. The Excel file is not identified by Bates numbers.

RESPONDENT:

Michael Sheehan

WITNESS:

Michael Sheehan

RUCO 11.6

Rebuttal Schedules – Please provide a copy in excel format with formula intact of any changes in the Company's Revenue Requirement Schedules (A-F), Cost of Capital, Cost of Service, Rate Design Schedules, Revenue Requirement Model, Proof of Revenue, Pro-forma adjustments, Exhibits, and any other excel worksheets used to develop the Company's rebuttal testimony.

RESPONSE:

Please see UDR 3.1 for the requested information, specifically the files listed in subfolders Revenue Requirement, Sch G&H Support, and Sch G&H Support Competitively-Sensitive Confidential for the requested files.

RESPONDENT:

David Lewis / Brenda Pries

WITNESS:

David Lewis / Craig Jones

ATTACHMENT B

Exhibit DJL-R-1

UNS Electric, Inc.
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
Test Year Ended December 31, 2014

	As Filed UNSE 12/31/14	STAFF Revised Pos.	RUCO Revised Pos.	UNSE Revised Pos.	STAFF Summary of Position	RUCO Summary of Position
Original Cost Rate Base - Unadjusted	$272,560,320	$ 272,560,320	$272,560,320	$ 272,560,320		
Rate Base Adjustments						
Acquisition Discount Adjustment	4,371,344	4,371,344	4,371,344	$ 4,371,344	No Adjustment	No Adjustment
Accumulated Deferred ITC	4,272,926	4,272,926	4,272,926	$ 4,272,926	No Adjustment	No Adjustment
Accumulated Deferred Income Taxes	(1,773,667)	(1,773,667)	(9,240,729)	$ (1,773,667)	No Adjustment	to reduce rate base for the NOL associated bonus depreciation.
Fortis Rate Base Adjustment	(10,249)	(10,249)	(10,249)	$ (10,249)	No Adjustment	No Adjustment
Gila River Adjustment	(11,389)	(2,011,389)	(11,389)	$ (2,011,389)	To Reduce RB by $2M related to depreciation expense as deferred by the accounting order for Gila River.	
ARO	(1,101,971)	(1,101,971)	(1,101,971)	$ (1,101,971)	No Adjustment	
Working Capital	(6,294,187)	(6,123,207)	(8,288,758)	$ (6,123,207)	CWC adjustment- Increase $187,756. D&O prepaid reduction by 50% ($16,778). Staff adjustment for D&O insurance is at Total Company not ACC jurisdiction. Staff also used 50% reduction based on total expense not average balance.	CWC and D&O prepaid
Total Adjustments to Rate Base	(547,193)	(2,376,213)	(8,008,826)	(2,376,213)		
Rate Base	$ 272,013,127	$ 270,183,980	$ 264,551,495	$ 270,183,980		
Requested Rate of Return	7.67%	7.22%	6.81%	7.22%	Capital Structure: 47.17 % debt @ 4.66% , 52.63% Equity @ 9.5%. FVI .50%. ROR on OCRB 7.22%	Capital Structure: 47.17 % debt @ 4.66% , 52.83% Equity @ 8.35%. FVI .82%. ROR on OCRB 6.81%
Required Operating Income OCRB	$20,852,600	$19,500,907	$17,466,854	$19,500,907		
Fair Value Increment of Rate Base	$83,704,602	$83,707,020	$80,579,090	$83,707,020		
Fair Value Rate Base (FVRB)	$355,717,730	$353,891,000	$345,130,586	$ 353,891,000	Modified from original Position: To correct formula error FVROR changed from 5.60% to 5.63%	Reflects OCRB proposed changes
Proposed FVROR	1.50%	0.50%	0.82%	0.50%		
Required Operating Income on FVRB	1,255,569	$418,548	$660,139	$418,548		
Original Operating Income - Unadjusted	$22,042,438	$22,042,438	$22,042,438	$22,042,438		
Operating Revenue Adjustments						
LFCR	(1,377,647)	(1,377,647)	(1,377,647)	(1,377,647)	No Adjustment	
Non-Retail Rev, Fuel & Purchase Power	-	7,781,533	3,080,705	7,781,533	Staff recommended a Base Cost of fuel of $0.053288 vs $0.048427 requested by UNSE. Staff's rate consists of actual costs from January through August 2015 and forecasted costs for September through December 2015.	RUCO adjusted base fuel revenue to reflect $0.056603 average rate. No corresponding expense adjustment.
Customer and Weather Adjustment	(6,021,912)	(6,021,912)	(6,021,912)	($6,021,912)	No Adjustment for Weather. Staff requests that the company monitor revenues and file quartarly. Concerns are surrounding the larger customers entering back into the market.	N/A
REST & DSM	(1,537,369)	(1,537,369)	(1,537,369)	($1,537,369)	No Adjustment	
Service Fees	95,034	$5,034	95,034	$95,034	No Adjustment	
Other Revenues	(45,506)	(45,506)	(45,506)	($45,506)	No Adjustment	
Total Adjustments to Operating Revenues	(8,887,400)	($1,105,867)	($5,798,695)	($1,105,867)		

UNS Electric, Inc.
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
Test Year Ended December 31, 2014

	As Filed UNSE 12/31/14	STAFF Revised Pos.	RUCO Revised Pos.	UNSE Revised Pos.	STAFF Summary of Position	RUCO Summary of Position
Operating Expense Adjustments						
Payroll Expense	(172,011)	(172,011)	(172,011)	(172,011)	Staff removed the Incentive Comp amounts associated with payroll. The adjustment however does not include Incentive comp. Staff use Total Incentive Comp and did not exclude the portion that goes to Capital. After conversation with Staff witness the adjustment will be Withdrawn.	No Adjustment
Payroll Tax Expense	(13,397)	(13,397)	(13,397)	(13,397)	Staff removed the Incentive Comp amounts associated with payroll. The adjustment however does not include Incentive comp. Staff used Total Incentive Comp and did not exclude the portion that goes to Capital. After conversation with Staff witness the adjustment will be Withdrawn.	No Adjustment
Pension & Benefits	(123,376)	(123,376)	182,472	(123,376)	No Adjustment	RUCO used a 3 year average for Medical and Dental - did not account for the amount that is O&M only.
Retiree Medical	(37,384)	(37,384)	(37,384)	(37,384)	No Adjustment	No Adjustment
Rate Case Expense	(53,349)	(53,349)	(36,682)	(53,349)	No Adjustment	Allowed $350K over 3yrs
Bad Debt Expense	358,151	489,791	358,151	489,791	Staff excluded Mercator write off from their normalization ($450K). Staff used a Three Year retail revenues total divided by 3 year retail expense.	No Adjustment
Depr. & Amort. Expense	6,624,227	6,624,227	6,624,227	6,624,227	No Adjustment	No Adjustment
Property Tax	(873,950)	(873,950)	(873,950)	(873,950)	No Adjustment	No Adjustment
Incentive Compensation	(169,378)	(14,023)	46,873	(14,023)	Staff adjusts for a 2yr average. And 50-50 sharing between ratepayers and Stakeholders.	To reduce Operating income for Wellness programs and Spot awards. And to reflect 50/50 sharing of PEP
Injuries and Damages	(355,542)	(35,442)	(11,727)	(35,442)	To remove the $1M insurance deductible we booked in 2013 but reversed in July 2015 due to a favorable outcome.	Ruco removed all of the $1,071,000 then applied a 3yr average
Membership Dues	10,590	10,590	26,107	10,590	No Adjustment	Ruco excluded all of UARG and 29.55% of EEI; leaving only their estimate of legislative advocacy
Gila River Deferred Cost	(3,100,000)	(3,100,000)	(3,100,000)	(3,100,000)	No Adjustment	No Adjustment
Fortis Acquisition Costs	5,522,093	5,522,093	5,522,093	5,522,093	No Adjustment	No Adjustment
Gila O&M and Outages	(3,370,536)	(3,370,536)	(3,370,536)	(3,370,536)	No Adjustment	No Adjustment
Income Taxes	5,174,155	4,915,650	4,751,180	4,915,650	To adjust for STAFF changes (bad debt, Inj&dam,Payroll,Incentive Comp, D&O, Interest Sync, Purchased Power)	Ruco interest Sync
OATT	(14,531,456)	(14,511,531)	(14,531,456)	(14,511,531)	Staff is recommending the OATT Revenue Requirement amount that is currently used for the TCA rate in effect during the test year (2013 Plant data) should be used.	No Adjustment
D&O Insurance	-	20,028	70,077	20,028	Removal of 50% of the D&O related expense.	To reflect a 50-50 sharing
Purchased Power	-	(7,781,533)	(3,090,705)	(7,781,533)	Corresponding adjustment to revenue	Corresponding adjustment to revenue
Total Adjustments to Operating Expense	(5,111,163)	(12,504,153)	(7,656,858)	(12,504,153)		
Total Net Adjustments	(13,998,563)	(13,610,020)	(13,453,353)	(13,610,020)		
Adjusted Operating Income	$8,043,875	$8,434,000	$8,589,085	$8,434,000		
Operating Income Deficiency	$14,064,294	$11,485,455	$9,557,907	$11,485,455		
Gross Revenue Conversion Factor	1.6084	1.6070	1.6084	1.6070	This is due to the removal of $450,000 bad debt expense reserve for mining company bankruptcy filing.	No Adjustment
Increase in Gross Revenue Requirement	$22,621,010	$18,457,000	$15,372,938	$18,457,000		

ATTACHMENT C

UNS Electric, Inc.
Docket No. E-04204A-15-0142
Test Year Ended December 31, 2014

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JMM-4	ORIGINAL COST RATE BASE - ACC JURISDICTIONAL
JMM-5	SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
JMM-6	RATE BASE ADJUSTMENT NO. 1 - REVERSE NET OPERATING LOSS CARRYFORWARD ACCUMULATED DEFERRED INCOME TAX OFFSET
JMM-7	RATE BASE ADJUSTMENT NO. 2 - ALLOWANCE FOR WORKING CAPITAL
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JMM-10	OPERATING INCOME ADJUSTMENT NO . 1 - Base Fuel Rates BY COMMISSION NOT APPLIED TO TEST YEAR BILLING DETERMINANTS
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UNS Electric, Inc.
Docket No. E-04204A-15-0142
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Surrebuttal Schedule JMM-1

REVENUE REQUIREMENT
ACC JURISDICTIONAL
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY ORIGINAL COST REBUTTAL	(B) COMPANY RCND REBUTTAL	(C) COMPANY FAIR VALUE REBUTTAL	(D) RUCO ORIGINAL COST SURREBUTTAL	(E) RUCO RCND SURREBUTTAL	(F) RUCO FAIR VALUE SURREBUTTAL
1	Adjusted Rate Base	$ 270,184	$ 437,598	$ 353,891	$ 270,049	$ 437,462	$ 353,755
2							
3	Adjusted Operating Income (Loss)	8,434	8,434	8,434	8,673	8,673	8,673
4							
5	Current Rate Of Return (Line 3 / Line 1)	3.12%	1.93%	2.38%	3.21%	1.98%	2.45%
6							
7	Required Operating Income (Line 13 X Line 1)	$ 19,920	$ 19,920	19,920	19,380	$ 19,380	$ 19,380
8							
9	Weighted Average Cost of Capital	7.22%	7.22%	7.22%	7.02%	7.021%	7.02%
10							
11	Fair Value Adjustment	0.15%	-2.67%	-1.59%	0.15%	-2.59%	-1.54%
12							
13	Required Rate of Return	7.37%	4.55%	5.63%	7.18%	4.43%	5.48%
14							
15	Operating Income Deficiency (Line 7 - Line 3)	$ 11,486	$ 11,486	11,486	10,707	10,707	10,707
16							
17	Gross Revenue Conversion Factor (Schedule JMM-2)	1.6070	1.6070	1.6070	1.6070	1.6070	1.6070
18							
19	Increase In Gross Revenue Requirement (Line 15 X Line 17)	$ 18,457	$ 18,457	$ 18,457	$ 17,206	$ 17,206	$ 17,206
20							
21	Adjusted Test Year Revenue	$ 156,716	$ 156,716	$ 156,716	$ 158,714	$ 158,714	$ 158,714
22							
23	Proposed Annual Revenue Requirement (Line 19 + Line 21)	$ 175,173	$ 175,173	$ 175,173	$ 175,920	$ 175,920	$ 175,920
24							
25	Required Percentage Increase In Revenue (Line 19 / Line 21)	11.78%	11.78%	11.78%	10.84%	10.84%	10.84%
26							
27	Rate Of Return On Common Equity	9.50%	9.50%	9.50%	9.13%	9.13%	9.13%

References:
Columns (A) Thru (C): Company Schedule A-1, C-1 and D-1
Column (D): Schedules JMM-3, JMM-8, and JMM-20
Column (E): Schedule JMM-2, Column (B)
Column (F): Average of Column (D) + Column (E) / 2

UNS Electric, Inc.
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Test Year Ended December 31, 2014

Surrebuttal Schedule JMM-2

GROSS REVENUE CONVERSION FACTOR, INCOME TAX CALCULATION

LINE NO.	DESCRIPTION	[A] Company Proposed	[B] RUCO Recommended
1	Gross Revenue	100.00%	100.00%
2	Less: Uncollectibel Revenue	0.29%	0.29%
3	Taxable Income as a Percent	99.71%	99.71%
4	Less: Federal and State Income Taxes	37.48%	37.48%
5	Changes in Net Operating Income	62.23%	62.23%
6	Gross Revenue Conversion Factor	1.6070	1.6070

UNS Electric, Inc.
Docket No. E-04204A-15-0142
Test Year Ended December 31, 2014

RATE BASE (OCRB, RCND and FVRB)
ACC JURISDICTIONAL
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY OCRB	(B) COMPANY RCND	(C) COMPANY FVRB	(D) OCRB/RCND % DIFF.	(E) RUCO OCRB	(F) RUCO RCND	(G) RUCO FVRB
1	Gross Utility Plant In Service	$ 664,701	$ 1,169,067	$ 916,884	175.88%	$ 664,701	$ 1,169,067	$ 916,884
2	Accumulated Depreciation	(296,962)	$ (561,910)	(429,436)	189.22%	(296,962)	(561,910)	(429,436)
3	Net Utility Plant In Service	367,739	607,156	487,448		367,739	607,156	487,448
4								
5	Citizens Acquisition Discount	(97,155)	$ (172,852)	(135,004)	177.91%	(97,155)	(172,852)	(135,004)
6	Less: Accu Amort Citizens Acq Discount	36,098	$ 69,682	52,890	193.03%	36,098	69,682	52,890
7	Net Citizens Acquisition Discount	(61,057)	(103,170)	(82,114)		(61,057)	(103,170)	(82,114)
8								
9	Total Net Utility Plant	306,682	503,986	405,334	164.33%	306,682	503,986	405,334
10								
11	Deductions:							
12	Cust. Advances For Const.	(3,833)	(4,268.465)	(4,051)	111.35%	(3,833)	(4,268)	(4,051)
13	Customer Deposits	(4,428)	(4,427.886)	(4,428)	100.00%	(4,428)	(4,428)	(4,428)
14	Other (ITC)	(422)	(421.645)	(422)	100.00%	(422)	(422)	(422)
15	Acc. Deferred Income Taxes	(35,161)	(64,616.383)	(49,889)	183.77%	(35,161)	(64,616)	(49,889)
16	Total Deductions	(43,844)	(73,734)	(58,789)		(43,844)	(73,734)	(58,789)
17								
18	Allowance - Working Capital	7,346	7,346	7,346	100.00%	7,210	7,210	7,210
19								
20	Regulatory Assets	-	-	-	100.00%	-	-	-
21								
22	Regulatory Liability	-	-	-	100.00%	-	-	-
23								
24								
25	TOTAL TEST YEAR RATE BASE	$ 270,184	$ 437,598	353,891		$ 270,049	$ 437,462	$ 353,755

References:
Columns (A) (B) (C): Company Schedule B-1
Column (D): Column (B) / Column (A)
Column (E): Schedule JMM-4, Column (C)
Column (F): Column (D) X Column (E)
Column (G): Average Of Column (E) + Column (F) / 2

UNS Electric, Inc.
Docket No. E-04204A-15-0142
Test Year Ended December 31, 2014

ORIGINAL COST RATE BASE - ACC JURISDICTIONAL (Shown in Thousands)

LINE NO.	DESCRIPTION	(A) COMPANY FILED AS OCRB	(B) RUCO ADJUSTMENTS	(C) RUCO ADJUSTED AS OCRB
1	Gross Utility Plant In Service	$ 664,701	-	$ 664,701
2	Accumulated Depreciation	(296,962)	-	(296,962)
3	Net Utility Plant In Service	367,739	-	367,739
4				
5	Citizens Acquisition Discount	(97,155)	-	(97,155)
6	Less: Accu Amort Citizens Acq Discount	36,098	-	36,098
7	Net Citizens Acquisition Discount	(61,057)	-	(61,057)
8				
9	Total Net Utility Plant	306,682	-	306,682
10				
11	Deductions:			
12	Cust. Advances For Const.	$ (3,833)	-	$ (3,833)
13	Customer Deposits	(4,428)	-	(4,428)
14	Other - Investment Tax Credits ("ITC")	(422)	-	(422)
15	Accumulated Deferred Income Taxes ("ADIT")	(35,161)	-	(35,161)
16	Total Deductions	(43,844)	-	(43,844)
17				
18	Allowance - Working Capital	7,346	(135)	7,210
19				
20	Regulatory Assets	-	-	-
21				
22	Regulatory Liability	-	-	-
23				
24				
25	TOTAL OCRB	$ 270,184	$ (135)	$ 270,049

Reconciliation to RCN (Thousands of Dollars)

	OCRB	RCN Ratio for ADIT	RCN
Company RCN as Filed			$ 437,598
RUCO ADIT Adjustment #1	$ -	1.8377	-
Cash Working Capital	(135)	1	(135)
	$ (135)		$ 437,462

References:
Column [A]: Company as Filed
Column [B]: RUCO Schedule 5
Column (C): Column (A) + Column (B)

UNS Electric, Inc.
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Test Year Ended December 31, 2014

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
(Thousands of Dollars)

		ACC Jurisdiction			
Line No.	DESCRIPTION	(A) Company Adjusted OCRB Rebuttal	[B] Rate Base Adjustment No. 1 Reverse Net Operating Loss Carry forward Accumulated Deferred Income Tax Offset	(C) Rate Base Adjustment No. 2 Working Capital	(D) RUCO Adjusted OCRB Recommended Balances
1	Gross Utility Plant in Service	664,701	$ -	$ -	$ 664,701
2					
3	Accumulated Depreciation	(296,962)	-	-	$ (296,962)
4	Net Utility Plant in Service	$ 367,739	$ -	$ -	$ 367,739
5					
6	Citizens Acquisition Discount	$ (97,155)	$ -	$ -	$ (97,155)
7	Accumulated Amortization - Citizens Acquisition Discount	36,098	-	-	$ 36,098
8	Net Citizens Acquisition Discount	$ (61,057)	$ -	$ -	$ (61,057)
9					
10	Total Net Utility Plant	$ 306,682	$ -	$ -	$ 306,682
11					
12	Customer Advances for Construction	$ (3,833)	$ -	$ -	$ (3,833)
13					
14	Customer Deposits	(4,428)			(4,428)
15					
16	Other - Investment Tax Credits ("ITC")	(422)			(422)
17					
18	Accumulated Deferred Income Taxes ("ADIT")	(35,161)	-		(35,161)
19	Total Deductions	$ (43,844)	$ -	$ -	$ (43,844)
20					
21					
22	Allowance for Working Capital	$ 7,346	$ -	$ (135)	$ 7,210
23					
24	Regulatory Assets	-	-	-	-
25					
26	Regulatory Liabilities	-	-	-	-
27					
28	Total Original Cost Rate Base	$ 270,184	$ -	$ (135)	$ 270,049

REFERENCES:
Column (A) Company Schedule B-1
Column (B) See RBM-4
Column (D) See RBM-5
Column (E) See Column (B) through (D)

UNS Electric, Inc.
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Test Year Ended December 31, 2014

Surrebuttal Schedule JMM-6

RATE BASE ADJUSTMENT NO. 1
Reverse Net Operating Loss Carryforward
Accumulated Deferred Income Tax Offset

Line No.	DESCRIPTION	(A) Company Proposed	(B) RUCO Adjustment	(C) RUCO As Adjusted
1	Accumulated Deferred Taxes	$ (35,161,108)	$ -	$ (35,161,108)
	ADIT NOLC Offset	$ -		
	ACC Jurisdictional Factor	0.0000		
		$ -		

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

UNS Electric, Inc.
Docket No. E-04204A-15-0142
Test Year Ended December 31, 2014

Surrebuttal Schedule JMM-7

ALLOWANCE FOR WORKING CAPITAL
LEAD/LAG DAY SUMMARY

LINE NO.	DESCRIPTION	(A) COMPANY ADUSTED TEST YEAR AS FILED	(B) RUCO Adj	(C) RUCO Adjusted Results	(D) Revenue Lag Days	(E) Exp Lag Days	(F) Net Lag Days	(G) Lead Lag Factor	(H) Cash Working Capital Requiredments
1	OPERATING EXPENSES								
2	Non-Cash Expenses:								
3	Bad Debts Expense	$ 506	$ -	$ 506	-		-		-
4	Depreciation	11,406	-	11,406			-		-
5	Amortization	(3,629)	(17)	(3,646)			-		-
6	Deferred Income Taxes	4,627	-	4,627			-		-
7	Total Non-Cash Expenses	$ 12,909	(17)	12,892					-
8									
9	Other Operating Expenses:								
10	Salaries & Wages	$ 4,616	$ -	$ 4,616	35.59	23.33	12.26	0.0336	155
11	Incentive Pay	329	(48)	281	35.59	267.00	(231.41)	(0.6340)	(178)
12	Purchased Power	62,965	1,997	64,962	35.59	33.79	1.80	0.0049	318
13	Transmission Other	9,014	-	9,014	35.59	40.67	(5.08)	(0.0139)	(125)
14	Meter Reading	574	-	574	35.59	33.67	1.92	0.0053	3
15	Customer Records & Coll Exp	1,169	-	1,169	35.59	34.94	0.65	0.0018	2
16	Office Supplies and Expenses	1,005	(16)	988	35.59	50.89	(15.30)	(0.0419)	(41)
17	Injuries and Damages	750	-	750	35.59	70.52	(34.93)	(0.0957)	(72)
18	Pensions and Benefits	1,960	(319)	1,641	35.59	51.37	(15.78)	(0.0432)	(71)
19	Support Services	6,059	-	6,059	35.59	44.77	(9.18)	(0.0252)	(153)
20	Property Taxes	6,733	-	6,733	35.59	212.00	(176.41)	(0.4820)	(3.245)
21	Payroll Taxes	376	-	376	35.59	12.00	23.59	0.0646	24
22	Current Income Taxes	-	-	-	35.59	-	35.59	0.0975	-
23	Interest on Customer Deposits	7	-	7	35.59	182.50	(146.91)	(0.4025)	(3)
24	Other O&M Expenses	25,050	-	25,050	35.59	41.21	(5.62)	(0.0154)	(386)
25	Total Other Operating Exp.	$ 120,607	$ 1,614	$ 122,221					
26									
27	Total Operating Expenses	$ 133,516	$ 1,598	$ 135,114					$ (3,771)
28									
29	Other Cash Working Capital Elements:								
30	Interest on Long-Term Debt	7,859	-	7,859	35.59	89.5	$ (53.91)	$ (0.1477)	(1,161)
31	Rev. Taxes and Assessments	11,717	-	11,717	35.59	49.43	$ (13.84)	$ (0.0379)	(444)
32									
33		$ 19,576	$ -	$ 19,576					$ (1,605)
34									
35	TOTAL CASH WORKING CAPITAL	$ 166,001		$ 167,582					
36									
37									
38	Pro Fc Pro Forma Operating Expenses - Excluding Income Taxes	$ 128,889		$ 128,889					
39	Less: Less: Other O&M	103,839		105,437					
40		$ 25,050		$ 23,453					

	Shown in Thousands
Total RUCO	$ (5,376,263)
Total Company Rebuttal	$ (5,234,865)
Cash Working Capital Adjustment With ACC Jurisdictioanl Ratio .95717	$ (135,343)
Pre-paid D&O Insurance Adjustment With ACC Jurisdictioanl Ratio .95328	$ -
Difference	$ (135,343)

58 References:
59 Column (A): - Company Schedule B-5
60 Column (B): RUCO Operating Income Adjustments
61 Column (C): Column (A) + (B)
62 Column (D): Company Schedule B-5
63 Column (E): Company Schedule B-5
64 Column (F): Column (D) - Column (E)
65 Column (G): Column (E)/365

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Surrebuttal Schedule JMM-8

SUMMARY OF OPERATING INCOME STATEMENT - ACC JURISDICTIONAL - ADJUSTED TEST YEAR AND RUCO
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY REBUTTAL AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'D
1	Operating Revenues:			
2	Electric Retail Revenues	$ 154,888	$ 1,997	$ 156,886
3	Sales for Resale	-	-	-
4	Other Operating Revenue	1,828	-	1,828
5				-
6	TOTAL OPERATING REVENUES	156,716	1,997	158,714
7				
8	Operating Expenses:			
9	Fuel, Purchased Power and Trans	85,304	1,997	87,301
10	Other Operations and Maintenance Exp	42,229	(385)	41,845
11	Depreciation and Amortization	13,060	-	13,060
12	Taxes Other than Income Taxes	6,140	-	6,140
13	Income Taxes	1,550	146	1,696
14	Rounding Differences	-	-	-
15	TOTAL OPERATING EXPENSES	148,282	1,759	150,041
16				
17	OPERATING INCOME (LOSS)	$ 8,434	$ 239	$ 8,673

References:
Column (A): Company Schedule C-1
Column (B): RUCO Schedule 9
Column (C): Column (A) + Column (B)

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Surrebuttal Schedule JMM-9
Page 1 of 2

OPERATING INCOME STATEMENT - ACC JURISDICTIONAL - ADJUSTED TEST YEAR AND RUCO RECOMMENDED ADJUSTMENTS

(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY Rebuttal AS FILED	(B) Adj. 1 Base Fuel Rates JMM-10	(C) Adj. 2 Not Used JMM-11	(D) Adj. 3 Normalize Medical and Dental Expenses JMM-12	(E) Adj. 4 Directors & Officers Ins. JMM-13	(F) Adj. 5 Wellness, Employee, Spot Award JMM-14
1	Operating Revenues:						
2	Electric Retail Revenues	$ 154,888	$ 1,997	$ -	$ -	$ -	$ -
3	Sales for Resale	-	-	-	-	-	-
4	Other Operating Revenue	1,828	-	-	-	-	-
5							
6	TOTAL OPERATING REVENUES	$ 156,716	$ 1,997	$ -	$ -	$ -	$ -
7							
8	Operating Expenses:						
9	Fuel, Purchased Power and Trans	$ 85,304	$ 1,997	$ -	$ -	$ -	$ -
10	Other Operations and Maintenance	42,229	-	-	(306)	-	(47)
11	Depreciation and Amortization	13,060	-	-	-	-	-
12	Taxes Other than Income Taxes	6,140	-	-	-	-	-
13	Income Taxes	1,550	-	-	-	-	-
14	Rounding Differences	0	-	-	-	-	-
15	TOTAL OPERATING EXPENSES	$ 148,282	$ 1,997	$ -	$ (306)	$ -	$ (47)
16							
17	OPERATING INCOME (LOSS)	$ 8,434	$ -	$ -	$ 306	$ -	$ 47

OPERATING INCOME STATEMENT - ACC JURISDICTIONAL - ADJUSTED TEST YEAR AND RUCO RECOMMENDED ADJUSTMENTS

(Thousands of Dollars)

(G) Adj. 6 PEP Expense JMM-15	(H) Adj. 7 Injuries and Damages JMM-16	(I) Adj. 8 EEI Dues JMM-17	(J) Adj. 9 Rate Case Expense JMM-18	(k) Adj. 10 Interest Synchronization JMM-19	(L) Adj. 11 Income Tax JMM-20	(M) RUCO as Recommended
$ -	$ -	$ -	$ -	$ -	$ -	$ 156,886
-	-	-	-	-	-	-
-	-	-	-	-	-	1,828
$ -	$ -	$ -	$ -	$ -	$ -	$ 158,714
$ -	$ -	$ -	$ -	$ -	$ -	$ 87,301
-	-	(16)	(17)		-	41,845
-	-	-	-	-	-	13,060
-	-	-	-	-	-	6,140
-	-	-	-	1	145	1,696
-	-	-	-	-	-	-
$ -	$ -	$ (16)	$ (17)	$ 1	$ 145	$ 150,041
$ -	$ -	$ 16	$ 17	$ (1)	$ (145)	$ 8,673

OPERATING INCOME ADJUSTMENT NO. 1
BASE FUEL RATES

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Electric Retail Revenues	$ 154,888,262	$ 1,997,488	$ 156,885,750
2				
3	Fuel, Purchased Power, and Transmission	$ 85,303,918.23	$ 1,997,488	$ 87,301,407

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

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Surrebuttal Schedule JMM-11

OPERATING INCOME ADJUSTMENT NO. 2
NOT USED

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1		$ -	$ -	$ -

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

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Surrebuttal Schedule JMM-12

OPERATING INCOME ADJUSTMENT NO. 3
MEDICAL AND DENTAL EXPENSE NORMALIZATION

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(D) RUCO AS ADJUSTED	(E) ACC Juridictional Factor	(F) ACC Juridictional RUCO ADJUSTMENT
1	Medical Expense	$ 2,205,353	$ (329,800)	$ 1,875,553	0.9603	$ (316,694)
2	Dental Expense	82,709	11,295	94,004	0.9603	$ 10,846
3	Total	$ 2,288,062	$ (318,505)	$ 1,969,557	0.9603	$ (305,848)
4						
5	RUCO's Calculation:					
6	Year	Medical Expense Amount				
7	2014	$ 2,205,353				
8	2013	1,863,496				
9	2012	1,557,810				
10	Three Year Average	$ 1,875,553				
11						
12	RUCO's Calculation:					
13	Year	Dental Expense Amount				
14	2014	$ 82,709				
15	2013	92,243				
16	2012	107,060				
17	Three Year Average	$ 94,004				

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

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Surrebuttal Schedule JMM-13

OPERATING INCOME ADJUSTMENT NO. 4
OFFICERS AND DIRECTORS INSURANCE

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(D) RUCO AS ADJUSTED	(E) ACC Juridictional Factor	(F) ACC Juridictional RUCO ADJUSTMENT
1	Officers and Directors Liability Insurance	$ -	$ -	$ -	0.9603	$ -
2						
3	RUCO's Calculation:					
4	Company Proposed	$ -				
5	Split between Ratepayers and Shareholder	50%				
6	RUCO Adjustment - Total Company	$ -				

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

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Surrebuttal Schedule JMM-14

OPERATING INCOME ADJUSTMENT NO. 5
WELLNESS INCENTIVE PROGRAM, EMPLOYEE RECOGNITION, AND SPOT AWARD

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED	(E) ACC Juridictional Factor	(F) RUCO AS ADJUSTED
1	Wellnes Incentive Program	$ 15,738	$ (15,738)	$ -	0.9603	$ (15,113)
2	Employee Recognition	10,740	(10,740)	-	0.9603	(10,313)
3	Spot Awards	22,000	(22,000)	-	0.9603	(21,126)
4	Total	$ 48,478	$ (48,478)	$ -	0.9603	(46,551)

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

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Surrebuttal Schedule JMM-15

OPERATING INCOME ADJUSTMENT NO. 6
UNS SHORT-TERM INCENTIVE PROGRAM

Line No.	DESCRIPTION	(A) 2014 Company Total	(B) Company Pro Forma Adjusment	(C) Total COMPANY PROPOSED	(D) RUCO ADJUSTMENT	(E) ACC Juridictional Factor	(F) RUCO AS ADJUSTED
1	FERC						
2	0581	$ -	$ -	$ -	$ -	1.0000	$ -
3	0583	-	-	-	-	1.0000	-
4	0592	-	-	-	-	1.0000	-
5	0593	-	-	-	-	1.0000	-
6	0901	-	-	-	-	1.0000	-
7	0908	-	-	-	-	1.0000	-
8	0920	-	-	-	-	0.9603	-
10	O&M Expense	$ -	$ -	$ -	$ -		$ -
11	0408 FICA Tax	-	-	-	-	0.9601	-
12	Total	$ -	$ -	$ -	$ -		$ -
	Less: RUCO removal of Company projected costs 12,122 x acc jurisdicition ratio of .9661						$ -
	Total RUCO adjustment						$ -

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

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Surrebuttal Schedule JMM-16

OPERATING INCOME ADJUSTMENT NO. 7
INJURIES AND DAMAGES

Line No.	UNSE Adjustment to Injuries & Damages	(A)	(B)	(C)	(D)
1	**Account Description**	**2012**	**2013**	**2014**	**Average for 3 Years**
2	Workers' Compensation	$ -	$ -	$ -	$ -
3	Workers' Compensation	-	-	-	-
4	Injuries & Damages	-	-	-	-
5					
6	Total for Three Year Period	$ -	$ -	$ -	$ -
7					
8					
9	Company Average for 3 years	$ -	Column (D) Ln 6		
10					
11	Expenses for Test Year	$ -	Column (C) Ln 6		
12					
13	Company Adjustment Using 3 Year Average	$ -	Column (A) Ln 9 - Ln 11		
14					
15	ACC Jurisdictional	96.027%			
16					
17	ACC Jurisdictional Adjustment	$ -	PER COMPANY'S Calculation		
18					
19					
20	RUCO's Adjustment to Injuries & Damages				
21					
22	**Account Description**	**2012**	**2013**	**2014**	**Average for 3 Years**
23	Workers' Compensation	$ -	$ -	$ -	$ -
24	Workers' Compensation	-	-	-	-
25	Injuries & Damages	-	-	-	-
26	RUCO Reduction in Injuries and Damages	-	-	-	-
27					
28	Total for Three Year Period	$ -	$ -	$ -	$ -
29					
30					
31					
32	RUCO does not believe that the Injuries and damages expense for $1,071,000 incurred at year ending 2013 should be included in the calculation for the the three year period. The expense is extraordinary in nature and should be excluded.				
33					
34					
35	RUCO'S Average for 3 years	$ -	Column (D) Ln 28		
36					
37	Expenses for Test Year	$ -	Column (C) Ln 28		
38					
39	Company Adjustment Using 3 Year Average	$ -	Column (A) Ln 35 + Ln 37		
40					
41	ACC Jurisdictional	96.027%			
42					
43	ACC Jurisdictional Adjustment	$ -	PER RUCO's Calculation		
44					
45					
46	**TOTAL RUCO ADJUSTMENT**	$ -	Line Column (A) Ln 18 + Column (A) Ln 44		

References:
Columns (A) through (D) Lines 3 through 18 provided by Company in UDR 1.01 Workpaper Schedules.

Columns (A) through (D) Lines 21 through 47 RUCO calculations

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Surrebuttal Schedule JMM-17

OPERATING INCOME ADJUSTMENT NO. 8
EEI DUES

Line No.	DESCRIPTION	(A) TEST YEAR AMOUNT	(B) COMPANY ADJUSTMENT	(C) COMPANY PROPOSED	(D) RUCO ADJUSTMENT	(E) RUCO ACC JURISDICTIONAL ADJUSTMENT
1	EEI Membership - USWAG	$ 3,500	$ (217)	$ 3,283	$ (1,035)	$ (994)
2	UARG - Membership Dues	15,123	-	15,123	$ (15,123)	$ (14,523)
3	Total Dues Expense	$ 18,623	$ (217)	$ 18,406	$ (16,158)	$ (15,517)

RUCO's Calculation:	
EEI - Membership	$ 3,500
RUCO's Disallowance	0.3575
Amount Disallowed	$ 1,251
ACC Jurisdictional Ratio	0.9603
ACC Jurisdictional Amount	$ 1,202
Reconciliation	
$217 x .9603 Already removed by Company	$ 208
$1,035 (1,251 - 217) x .9603	994
	$ 1,202
UARG Dues $15,123 x .9603	$ 14,523

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

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Surrebuttal Schedule JMM-18

OPERATING INCOME ADJUSTMENT NO. 9
RATE CASE EXPENSE

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO RECOMMENDED	(C) RUCO ADJUSTMENT
1	Rate Case Expense	$ 400,000	$ 350,000	
2	Normalization Years	3	3	
3	Rate Case Expense	$ 133,333	$ 116,667	$ (16,667)

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

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Surrebuttal Schedule JMM-19

Operating Adjustment No. 10
Interest Synchronization

Line No.	Description	Tax Rate	[A] Company Proposed	[B] RUCO Recommended
1	Adjusted Rate Base		$ 270,184,177	$ 270,048,834
2	Weighted Cost of Debt		2.20%	2.20%
3	Synchronized Interest Deduction		$ 5,938,978	$ 5,936,003
4	Increase (Decrease) in Deductible Interest			$ (2,975)
5	State Income Taxes	5.48%		$ 163
6	Federal Taxable Income			$ (2,812)
7	Federal Income Taxes	32.14%		$ 904
8	Increase (Decrease) to Income Tax Expense			$ 1,067

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

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Surrebuttal Schedule JMM-20

OPERATING INCOME ADJUSTMENT NO. 11
INCOME TAX EXPENSE

Line No.	RUCO Income Tax Calculation on RUCO Adjustments (Thousands of Dollars)		
1	Operating Revenues:		
2	Electric Retail Revenues	$	1,997,488
3	Sales for Resale		-
4	Other Operating Revenue		-
5	Total Operting Revenue	$	1,997,488
6			
7	Operating Expenses:		
8	Fuel, Purchased Power and Trans	$	1,997,488
9	Other Operations and Maintenance Exp	$	(384,582)
10	Depreciation and Amortization	$	-
11	Taxes Other than Income Taxes	$	-
12	Pre -Tax Operating Expenses	$	1,612,906
13	Pre -Tax Operating Income	$	384,582
14	Income Taxes	$	144,653
	Combined Effective Tax Rate from Company's C-3		37.6130%

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

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Surrebuttal Schedule JMM-21

COST OF CAPITAL - ORIGINAL COST RATE BASE
Thousands of Dollars

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED	(D) PERCENT	(E) COST RATE	(F) WEIGHTED COST RATE
1	Long-term Debt	169,590	-	169,590	47.17%	4.82%	2.27%
2							
3	Common Equity	189,932	-	189,932	52.83%	9.50%	5.02%
4							
5	TOTAL CAPITAL	$ 359,522	$ -	$ 359,522	100.00%		
6							
7	WEIGHTED COST OF CAPITAL (Sum Lines 1 Thru 5)						7.29%
8							
9							

10 **COST OF CAPITAL - FAIR VAUE RATE BASE**

11

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED	(D) PERCENT	(E) COST RATE	(F) WEIGHTED COST RATE
12–15							
16							
17	Long-term Debt	169,590	$ -	$ 169,590	47.17%	4.66%	2.20%
18							
19	Common Equity	189,932	-	189,932	52.83%	9.13%	4.82%
20							
21	TOTAL CAPITAL	$ 359,522	$ -	$ 359,522	100.00%		
22							
23	WEIGHTED COST OF CAPITAL (Sum Lines 1 Thru 5)						7.02%
24							
25							
26					Fair Value Incement		0.50%

References:
- Column (A): Company Schedule D-1
- Column (B): Testimony, RBM
- Column (C): Column (A) + Column (B)
- Column (D): Column (C), Line Item / Total Capital
- Column (E): Testimony, RBM
- Column (F): Column (D) X Column (E)

UNS ELECTRIC, INC.

DOCKET NO. E-04204A-15-0142

SURREBUTTAL TESTIMONY

OF

LON HUBER

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

FEBRUARY 23, 2016

TABLE OF CONTENTS

I. INTRODUCTION **1**

II. CONCERNS WITH PROPOSED MANDATORY DEMAND RATE **2**

III. OTHER CONCERNS **19**

IV. SOLUTIONS TO PROBLEMS WITH UNSE'S PROPOSED RATE DESIGN **27**

ATTACHMENTS

Selected Company response to RUCO's data request .... A
The National Association of State Utility Consumer Advocates Resolution 2015-1 .... B

EXECUTIVE SUMMARY - SURREBUTTAL

The Residential Utility Consumer Office ("RUCO") has reviewed the rebuttal testimony of UNS Electric, Inc. ("Company, UNS, or UNSE"), and the various interveners' direct testimony on rate design.

RUCO continues to recommend a traditional rate design for 98 percent of UNS customers and recommends three options for the 2 percent of UNSE customers that are Distributed Generation (DG) customers. RUCO is opposed to both Staff's and the Company's proposed mandatory demand rates, neither of which are in the interest of ratepayers and should be rejected by the Commission.

RUCO is perplexed as to why Staff, and now the Company, are pushing a mandatory demand rate onto residential ratepayers with such urgency. In fact, there is such a rush that customers will not even have a full year of data to understand the potential impacts of their demand charge. This is important as there are both summer and winter charges (which are illogically the same price). It seems like Staff is pursuing a policy for policy sake without considering the impact to ratepayers. In fact, it was the Company that originally held back from proposing a mandatory demand rate because they were not ready, and it was the Company that suggested safeguards for ratepayers in their rebuttal.

If Staff seeks to solve the rooftop solar issue with this mandatory demand rate, there is no need. Both the Company and RUCO agree that solar participants can be treated differently than the standard residential customer. Partial requirements customers and Full Requirements are not "similarly situated". Decades of partial requirements customers and other policies back this up. Moreover, RUCO offered a solution to the claim of discrimination by certain solar advocates should this issue become divisive. RUCO put forward a "no export" option if a solar customer seeks to be on a traditional rate. This option was approved in Hawaii and a solar customer can get the same payback, broadly speaking, if they have enough load and a properly sized system. Further, RUCO offered two other options for solar customers, a rate design for sophisticated DG adopters, and a simple fixed credit rate tied to REST compliance.

In sum, there is no justification as to why rates must change dramatically and all within a year. Instead of allowing customer choice, nearly every residential UNS ratepayer will have only a single rate plan in which they are exposed to a new charge, one they have never seen before. Add in the lack of actionable data due to old meter technology plus the lackluster education plan and one should conclude that this policy is frankly unacceptable and detrimental to residential ratepayers.

I. INTRODUCTION

Q. Please state your name for the record.

A. My name is Lon Huber.

Q. Have you previously filed testimony regarding this docket?

A. Yes, I have. I filed direct rate design testimony in this docket on December 9, 2015.

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony will primarily address the Company/Staff's position on mandatory demand rates with brief mention of other parties' positions on rate design.

Q. How is your surrebuttal testimony organized?

A. My surrebuttal testimony is presented in three sections as below:

i. Introduction

ii. Concerns with UNSE's proposed mandatory demand rate;

- a. Equity and fairness in UNSE's proposed mandatory demand rate
- b. Customer education plan and timeline
- c. Time of Use demand rate design

iii. Other concerns

- a. Concerns regarding UNSE's proposed increase in fixed charges
- b. Concerns regarding UNSE's rate design as a means to recover fixed costs.

iv. Solutions to problems with UNSE's proposed rate design

Q. Are there any corrections you would like to make at this time?

A. Yes. When formulating the demand charge for the Advanced DG rate, RUCO asked the Company to provide a breakdown of fixed costs, customer costs, and variable costs. In the response, customer costs were inadvertently placed in the fixed cost category as well as the appropriate customer category. This led to a double counting of customer costs when calculating the demand charge for the Advanced DG rate. The correct figure should be $16 per kW per month for summer months. This figure also takes into account an estimate of the small impact a six-hour time-of-use (TOU) period and a three-hour averaging may have on the ultimate demand charge level.

II. CONCERNS WITH PROPOSED MANDATORY DEMAND RATE

a. Equity and fairness in UNSE's proposed mandatory demand rate

Q. How many Small General Service and Residential customers does the Company propose to move to the new three-part rate?

The Company now proposes to move all Small General Service ("SGS") and residential customers to a demand rate.

Q. What is the Company's stated motivation for moving all customers to this mandatory demand rate instead of only some customers?

A. The Company cites equity[1] and fairness[2] as motivation for moving all customers to the proposed demand rate.

---

[1] See Rebuttal Testimony of H. Edwin Overcast page 2, line 12

[2] Ibid. page 10, lines 5-6

Q. Does RUCO support moving all customers to a mandatory demand rate as an equitable and fair practice?

A. No. The Company argues that all SGS and residential customers should be treated similarly under the same mandatory demand rate because "using the same rate sends the same price signals"[3] to customers with like service characteristics. Utilities treat and categorize customers into different classes based on many factors. This is true for UNSE as well. Existing examples of customer classes include, CARES discount, agricultural, etc.

The utility ratemaking principle of fairness does not require all customers to be subject to the same rates, but rather be subject to rates that are fair. The proposal to require all customers to move to a mandatory demand rate is a misguided attempt at ensuring fair treatment.

Q. Do customers prefer rate options?

A. Yes. Utilities have increasingly been offering their customers more rate options. Using OpenEI US Utility Rate database data, the average number of residential rate options offered by utilities climbed from 1.87 residential rate options in 2013 to 3.2 residential rate options per utility in 2015[4]. This increase in rate offering also leads to an increase in customer satisfaction. J.D. Power senior director of energy, Andrew Heath stated recently, "the thing that really differentiates the top utilities, they provide the customer some form of choice." Heath goes on to state the utilities that offer greater choice, experience "a significant uplift in terms of overall customer

[3] See Rebuttal Testimony of H. Edwin Overcast page 48, lines 1-2
[4] http://en.openei.org/apps/USURDB/

satisfaction.[5]" Simply, customers prefer more options and do not appreciate a 'one size fits all' rate plan.

Q. Have UNS, TEP, and APS boasted about how they offer many different rate options to their customers?

A. Yes. In the deregulation debate in 2013, all the utilities mentioned their many rate options as a reason not pursue market restructuring. In the filings, it was clear that the companies were proud of their diverse offerings.

Tucson Electric Power Company and UNS Electric, Inc. stated the following:

> "Advocates also overlook the multitude of choices available to customers served by the Companies and other regulated Arizona utilities. Our customers can choose time-of-use rates, fixed price plans, "green" energy alternatives and incentives for energy efficiency and renewable power without forgoing the consumer protections offered in our regulated system."[6]

Arizona Public Service:

> "APS offers five varieties of residential time-of-use ("TOU") rates as well as TOU options for virtually all its commercial and industrial customers, including a TOU offering for schools specifically designed at their request. The Company offers demand response and energy efficiency programs, interruptible rates (as requested by some of the Company's larger customers), special contracts, combined metering

[5] http://www.utilitydive.com/news/for-top-utilities-customer-satisfaction-hinges-on-empowerment/402618/
[6] TEP and UNSE Response Letter to Commissioners in Docket NO. E-00000 W-13-0135, page 10

and billing, and other rate or service offerings. One would be hard pressed to find any electric utility in this country that provides such a wide range of options to over one million customers."[7]

Q. Does the Company propose customer subsets for differential treatment?

A. Yes. In H. Edwin Overcast's Rebuttal testimony, he defines partial and full requirement customers and later suggests these two classes to be treated differently. Full requirement customers receive all their electricity from the utility, partial requirement customers receive some electricity for the utility, and the rest from DG. This creates two classes of customer.

In his definition of these two classes, Overcast also suggests that within the previously defined full and partial requirement classes, "Partial requirement customers differ from full requirement customers and from each other[8]". This suggests the partial requirement subset can be further refined. Thus differentiating DG and non-DG customers would not be a departure from normal ratemaking process.

Q. Could partial and full requirement customers be subject to different rate designs?

A. This is what RUCO is proposing. Two optional rates for new DG customers, as detailed later in this testimony, will allow UNSE to treat the two classes differently without being unduly discriminatory.

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[7] APS Response Letter to Commissioners in Docket NO. E-00000 W-13-0135, page 2
[8] Rebuttal Testimony of H. Edwin Overcast page 10, lines 5-6

Q. Has the Company proposed applying a demand rate to a subset of their customers?

A. Yes. In fact, the Company proposed exactly this originally. In the Company's Direct Testimony mandatory three-part rates were proposed for the subset of DG customers that install distributed generation after June 1 2015, and optional for other non-DG SGS and residential customers[9].

Q. Has the Company changed its position since this initial proposal?

A. Yes. In its Rebuttal Testimony, the Company has expressed support for Staff's recommendation of a mandatory demand rate for all customers be adopted in this rate case.

Q. Why did UNSE not propose mandatory demand rates in its initial proposal?

A. In his Direct Testimony dated May 5, 2015, Dallas Dukes states "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."[10]. Later, in his Rebuttal Testimony Dukes states, mandating all customers to move to a mandatory demand rate in the initial proposal would have been 'somewhat aggressive'[11]. It is unclear what changes occurred to reduce the demand rates to an acceptable level of aggressiveness between Dukes' two testimonies. Further demonstrating the Company's own doubt, Craig Jones states "three-part rates for all customers is a special

[9] Direct Testimony of Carmine Tilghman page 8, line 21
[10] See Direct Testimony of Dallas Dukes page 10 lines
[11] See Rebuttal Testimony of Dallas Dukes beginning on page 4, line 7

circumstance which may yield results that were unintended.[12]" Therefore, "UNS Electric could support keeping the rate design portion of this rate case open for a period of time in the event that significant unintended consequences arise that adversely affect the Company or its residential or SGS customers."[13]

Q. In RUCO's opinion, does the Company and Staff's position reflect the principle of rate gradualism?

A. No. The Company's original proposal represented a more gradual shift by moving some, but not all customers to a radically new rate design. However, the Company's present proposal is not gradual and subjects all UNS customers to this radical shift in a way that RUCO believes will be confusing and harmful.

b. Customer education plan and timeline

Q. Why will UNSE's proposed mandatory demand rate be confusing for customers?

A. Among other reasons, UNS does not have the right technology deployed to adequately inform ratepayers of their demand usage?

Q. Please explain.

A. There are two types of advanced meters generally used today, Advanced Metering Infrastructure (AMI) meters and Automatic Metering Reading

[12] See Rebuttal Testimony of Craig Jones page 6, lines 15-16
[13] See Rebuttal Testimony of Craig Jones page 6, lines 17-18

(AMR) meters. According to General Electric, a meter manufacturer with experience in both AMI and AMR meters, AMR meters are older technology that provides one-way communication from the meter to the utility, AMI meters provide two-way communication, from the utility company to the customer[14]. This means only AMI meters can interface directly with customers about their demand usage. Currently, UNSE has no AMI meters installed[15]. Therefore, UNSE does not have the optimal technology in place to support the proposed changes. While AMR meters can provide interval data, it is RUCO's understanding that the customer will not be able to receive data in a timely manner because it must first go through the Company.

Q. Have you reviewed the direct testimony of Staff witness Howard Solganick and Thomas M. Broderick?

A. Yes.

Q. Please summarize Staff's testimony as it relates to customers' ability understand and adapt to UNS' proposed new rate structure.

A. Mr. Broderick states on page 7 of his direct testimony:

> "Staff believes that new meter technology, internet communications portals, and smart phone applications have made it feasible and much easier for residential customers to understand and accept a three-part tariff than ever before."

[14] General Electric's website; http://geappliance.esecurecare.net/app/answers/detail/a_id/22/~/what-is-the-difference-between-amr-and-ami-meters%3F
[15] RUCO data request 11.3

Mr. Broderick states on page 8 of his direct testimony:

> "Staff believes there will only be a temporary challenge for residential customers to understand, accept and adapt if the Company develops and implements a customer education program. Staff requests that UNSE define and develop the details for a rate migration transition process and share with the parties in its rebuttal testimony."

Further, Mr. Solganick states on page 8 of his direct testimony:

> "As a residential customer, my electric utility provides me with access to a portal where I can view my energy consumption." Later Solganick states, "My utility also provides me (with a two-day delay) my hourly energy consumption, which is equivalent to hourly demand. From this timely information, I can determine the peak period(s) of energy usage and then decide if I wish to change my energy usage in the future."

Q. Does UNS currently have this technology to support Mr. Broderick and Mr. Solganick's conclusions?

A. Not entirely. Based on RUCO data request 11.3. UNS does not have the current technology as 90.5% have AMR meters, and few customers have AMI meters.

Q. Is there currently an internet portal that UNS customers can log into to check their usage and demand profile?

A. No.

Q. Is Staff aware that UNS customers are unable to track their usage and demand in the way that Mr. Solganick described?

A. Yes. In response to data request 1.5 from RUCO, Staff stated that Mr. Solganick "was unable to find a UNSE portal with that capability."

Q. Does Staff recognize that there will be additional costs incurred by the Company (and ultimately ratepayers) to provide access to this data?

A. Yes. Staff recognizes that "the costs to develop a portal depends on the existing capabilities of the Company's infrastructure including website, customer information system, meter data management systems and whether the website would be extended to its affiliate TEP."

Q. Did Staff estimate what these costs will be?

A. No. However, the Company estimates a cost of $650,000 in response to RUCO data request 11.4.

Q. Does RUCO have further concerns regarding UNSE's proposed usage portal?

A. Yes. Only 76.2% of Arizonans have access to high speed internet, this is below the national average of 78.1%[16]. High speed internet is vital for users to access their electricity usage. Customers could also access their usage data using a smartphone. As of October 2014, only 64% of US adults own a smartphone[17]. This leaves a sizeable portion of UNSE customers without access to their usage even if it is made available through a portal.

[16] 2013 US Census Report https://www.census.gov/history/pdf/2013comp-internet.pdf
[17] Pew Research Center Mobile Technology Factsheet (October 2014) http://www.pewinternet.org/fact-sheets/mobile-technology-fact-sheet/

Q. What is RUCO's synopsis of Staff's recommendation?

A. RUCO finds it telling that Staff admitted that it will be challenging for customers to understand, at least at first. Staff places faith in a yet to be completed education plan and new technology that hasn't been developed yet and may not ever reach a large portion of UNS customers.

Q. What does this mean for ratepayers?

A. Higher costs in the form of added infrastructure in order to meet the requirements of Staff's mandatory demand rate. As well as confused customers lacking the connectivity and the hardware to understand the new charges.

Q. Does a Company witness also question the understandability of more advanced rate designs?

A. Yes. Dr. Overcast on page 33 of his testimony speaks to this and his answer was to undertake a 'gradual process done in steps'. To reduce confusion his first suggestion was to phase out the third tier of kWh rates followed by a move to seasonal and time differentiated energy charges.[18] Noticeably, he did not mention carrying out a rapid and complete switch to a three part rate design for all residential customers as Staff and the Company proposes.

Q. Does UNSE propose a timeline for their education plan and ultimate rollout of the proposed rates?

A. Yes. Summarized as:

[18] See Rebuttal Testimony of H. Edwin Overcast page 33 lines 15- 19

- May to June 2016. UNSE Implements transitional rates
- Present to December 2016. Analyze billing data
- May to October 2016. Customer education plan rolled out
- No later than November 2016. UNSE provides usage and demand data to customers.
- 1st quarter 2017. All residential and SGS customers moved to three-part rates and a redesigned bill introduced.[19]

Q. Does RUCO foresee issues with this timeline?

A. Yes. The proposed timeline is very tight to allow a full three months for customer demand data as proposed. All customers are expected to have AMR meters installed by the end of 2016[20]. Any setbacks will negatively impact this timeline.

Q. The timeline suggested provides some customers only three months of demand data before charging demand rates. Does RUCO feel this is adequate?

A. No. Three months of usage data will not provide enough information for customers to understand how their behavior will impact their electric bills. RUCO suggests greatly increasing this timeline before issuing bills using the new rates. The seasonal temperature variability in UNSE territory generally leads to higher usage and demand in summer, particularly due to air conditioning use. During shoulder seasons, air conditioning use is reduced, therefore demand during this time is unlikely to represent demand

[19] See Rebuttal Testimony of Dallas Dukes page 13 lines 1 - 12
[20] See Rebuttal Testimony of David Hutchens page 7, lines 10 -11.

during summer. For these reasons, RUCO takes issue with the lack of summer data available to customers. As proposed, the impact of three-part rates will not provide customers with accurate bill impacts before bills are issued.

Q. Does Staff believe it will be a challenge for residential customers to understand and accept a three-part tariff?

A. Yes. However, Staff says this challenge will be temporary if the Company implements a customer education program.

Q. Have you reviewed UNSE's Education Campaign, Exhibit DJD-R-1?

A. Yes, I have.

Q. Does RUCO have any comments about UNSE's proposed Education Campaign?

A. Yes. The listed campaign components are minimally specific and do little to ensure a customer will properly understand the changes. There is also little mention of education about demand management. RUCO feels that a complicated change such as a mandatory demand charge cannot be adequately explained using a bill insert and brochure. These are likely the only materials most customers will actually view.

Q. Does Staff explain how this education program will help customers understand and act upon their demand if they have no access to data about their demand?

A. No.

Q. Does RUCO have evidence suggesting UNSE's bill design is difficult for customers to understand?

A. Not directly, but generally it is found that customers have difficulty understanding traditional bills even without complicated demand charges. According to one study, only 39% of survey respondents were able to correctly respond to a question about the expected savings by reducing one's kWh usage[21]. The same study also found no single question in the bill interpretation section was answered correctly by more than 70% of respondents.

Q. Are there existing tools for customers to better understand energy usage and demand?

A. There are many tools to help customers understand kWh usage but few tools consider demand. Existing government programs serve as further evidence that customers cannot understand demand charges. The US government's online calculator tool for estimating appliance and home energy use only allows users to input an appliance wattage and cost per kWh[22]. Similarly, the Federal Trade Commission has adopted the recognizable yellow Energyguide label for new appliances. Both the calculator and label only consider yearly kWh performance and estimated yearly operating cost, they make no consideration for kW demand[23]. Using these tools, a reasonable customer could expect a new appliance to have a predictable impact to their estimated yearly operating cost. If the new appliance increased their peak demand, the customer would receive a

[21] Southwell, Brian G., et al (2012) Americans' Perceived and Actual Understanding of Energy
[22] http://energy.gov/energysaver/estimating-appliance-and-home-electronic-energy-use
[23] http://www.consumer.ftc.gov/articles/0072-shopping-home-appliances-use-energyguide-label

larger and unexpected bill. This represents a greater lack of customer understanding and a lack of adequate education tools.

Q. Who does RUCO believe should be responsible for demonstrating that UNSE customers will adequately comprehend the three-part tariff and understand how to manage their electricity bills?

A. RUCO believes the burden of proof is on Staff and the Company to demonstrate this.

Q. Are there other reasons why you have concerns about UNS' ability to develop and implement a customer education plan about mandatory demand charges? Please explain.

A. Yes, I have other reasons to be concerned. UNS' Residential Time-of-Use and Time-of Use-Super Peak tariffs (RES-01 TOU and RES-01 TOU SP) have very low subscription rates. During the test year, UNS reported an average of 230 customers on its Residential Time-of-Use tariff and only one customer on its Time-of-Use Super Peak tariff. This equates to less than 0.5% of residential customers. In comparison, 52% of APS customers are on time-of-use rates.[24] This raises concerns about UNS' ability to communicate to its customers about their rate offerings - especially non-standard ones - and to communicate specifically about energy usage as it relates to system peak.

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[24] Ryan Randazzo (2015), Arizona leads California on time-of-use electricity plans. http://www.usatoday.com/story/money/2015/05/26/arizona-california-time-of-use-electricity/27985581/

Furthermore, given that these charges would be mandatory for all residential customers, UNS would need to execute a communication and education plan that touched all residential customers and educated them about their energy usage. Notably, UNS has faced complaints in the past when it has tried to educate a broad number of customers about their energy usage. When UNS implemented its Home Energy Reports program, it "received a number of complaints from enrollees… generally concerning the report being delivered 'unsolicited,' on an opt-out basis, rather than an opt-in."[25] These complaints were an influencing factor in UNS' decision to cancel the program.

c. Time of use demand rate design

Q. Please summarize your comments regarding the Company's proposed Time of Use rates.

A. RUCO supports a time of use rate design, however as proposed, the Time of Use demand rate does not accurately collect costs from customers as they are incurred to the utility. RUCO is also in disagreement with the company over the duration of the proposed demand peak.

[25] UNS Electric, Inc.'s Annual Demand-Side Management Progress Report, Docket No. E-00000U-14-0049

Q. Do you have comments regarding the inability of the proposed Time of Use demand rate to accurately collect costs from customers as they are incurred to UNSE?

A. Yes. The proposed rate does not differentiate demand as it contributes to seasonal peak demand. This means summer and winter peak costs are recovered as if they cost UNSE equally. Since the Company's plan is to 'recover generation costs through the demand charge' this contradicts the Company witness Dr. Overcast.[26] In his article attached to his Rebuttal Testimony, Overcast states "It will be important to develop seasonal and diurnal periods based on underlying marginal costs" [27].

Q. Please describe how UNSE's proposed demand rate peak is too long in duration.

A. UNSE's proposed peak demand times are from 2 pm to 8 pm. This is a 6-hour timeframe which customers are expected to minimize demand. This is an unreasonable expectation that regular customers can realistically monitor and reduce their usage over this timeframe, at least initially and without technology assistance. A shorter timeframe, such as 4 pm to 7 pm, is easier for customers to respond to and more accurately represents the peak demand times.

[26] See Rebuttal Testimony of Dallas Dukes beginning on page 8, line 24
[27] Overcast, Edwin H. Smart Rates for Smart Utilities page 15

Q. Are there other effects of the peak demand rate that are not in customer's best interest?

A. Yes. UNSE cites Bonbright's principles of rate design in several instances throughout various testimony including Overcast[28]. RUCO feels this wide peak time does not represent the principle of practicality. It is simply, impractical to discourage behavior that contributes to a standard customer's peak demand for nearly all evening hours. A demand peak that is narrower would be more practical.

Q. Have you conducted in depth analysis of the customer impacts from the three part rate?

A. No, the tight timeline and limited data available, prevented me from conducting an in-depth review. Since Staff did not provide a rate schedule with details around their vision of a three part rate, I had only the time from the Company's rebuttal.

Q. In that time did you conduct any analysis?

A. Yes, but at a very high level. I found that compared to the current two part rate, the proposed three part rate provides a significant increase to the bill of lower than average users and a discount to higher than average users. Using 795 kWh per month, the monthly average as seen in UNS's 2,309 smart meter customer sample, the results are stark. Any customer between that average and 250 kWh per month in usage will be paying 21% more than under current rates. I purposely excluded very low users or else that figure would be even larger. Conversely, if a household uses over 1,500

[28] See Rebuttal Testimony of Edwin H. Overcast page 44, beginning on line 5

kWh a month they will receive a 3% discount compared to the current rate structure.

III. OTHER CONCERNS

a. Concerns with proposed increase in fixed customer charge

Q. What is the National Association of State Utility Consumer Advocates ("NASUCA")?

A. NASUCA is an association comprised of many consumer advocates from numerous states and the District of Columbia. NASUCA's members are designated by the laws of their respective jurisdictions to represent the interests of utility consumers before state and federal regulators and in the courts. RUCO is a member of NASUCA.

Q. Has NASUCA taken a position on increased fixed charges?

A. Yes. NASUCA recently adopted resolution 2015-1

Q. What does NASUCA state in resolution 2015-1, "OPPOSING GAS AND ELECTRIC UTILITY EFFORTS TO INCREASE DELIVERY SERVICE CUSTOMER CHARGES"?

A. NASUCA opposes increasing the basic service charge. I have included a copy of this resolution (see Attachment B).

Q. Does UNSE's proposed rate design include increased fixed charges?

A. Yes

Q. Does UNSE believe fixed costs should be recovered primarily through fixed charges?

A. Yes. Craig Jones argues that the proposed rates "still leave a significant percentage of the Company's fixed costs subject to recovery through volumetric rates." but the proposed rates "are a good start in addressing appropriate fixed cost recovery."[29] This indicates that UNSE believes fixed costs should be recovered as fixed charges, with some combination of demand charges from their customers.

Q. Does RUCO agree with UNSE's method of fixed cost recovery?

A. No. There is no fundamental reason that fixed costs must be recovered through fixed prices or unavoidable demand charges. In fact, many industries in the global economy incur fixed costs that are ultimately recovered through prices that are not fixed. For example, gasoline is priced on a volumetric basis ($ per gallon), despite the fact that there are many fixed costs associated with its production (e.g. refineries, pipelines, etc.). This is further argued by Bonbright; ""regulation should allow a fair rate of return, but not guarantee or protect a regulatee against mismanagement or adverse business conditions"[30].

[29] See Rebuttal Testimony of Craig Jones page 5, lines 12 - 14
[30] Bonbright, James Cummings (1961) Principles of Public Utility Rates page 382

Q. Other than increased fixed charges, are there other ways utilities such as UNSE could recover unrecovered fixed costs?

A. Yes, there are several. These options range from implementing new time-of-use demand rates (which is RUCO's proposal) to simply increasing UNSE's current volumetric rates.

Q. Does RUCO support increased fixed charges as a way to increase fixed cost recovery?

A. No. For reasons explained previously in our testimony, we don't support increased fixed charges. RUCO finds additional support for its argument from Bonbright: "Regulation, it is said, is a substitute for competition. Hence its objective should be to compel a regulated enterprise, despite its possession of a complete or partial monopoly, to charge rates approximating those which it would charge if free from regulation, but subject to the market forces of competition."[31] We believe there are many options, such as RUCO's proposal, that are better for customers while still ensuring greater fixed cost recovery for UNSE.

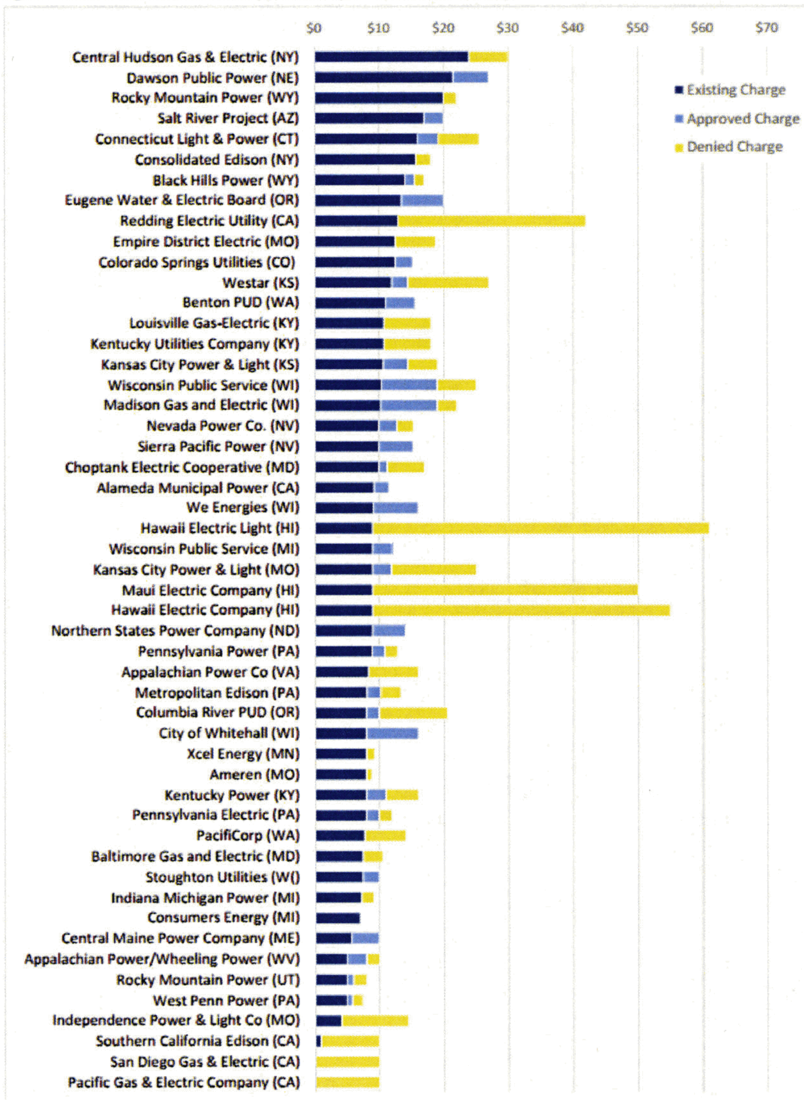
Q. Have there been other recent commission decisions regarding increased mandatory fixed charges?

A. Yes. Recent decisions by commissions in several states have either denied entirely or scaled back proposals to increase mandatory fixed charges proposed by utilities. Synapse recently analyzed 51 proposals decided between September 2014 and November 2015 and found that 41% of these proposals were rejected, and 33% were scaled back. The average

[31] Bonbright, James Cummings (1961) Principles of Public Utility Rates page 141

approved fixed charge for these decisions is $11.87[32]. These decisions are summarized below.[33]

Figure 12. Finalized decisions of utility proceedings to increase fixed charges



Notes: Denied includes settlements that did not increase the fixed charge.

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[32] Whited, M., Woolf, T., & Daniel, J. (2016). Caught in a Fix: The Problem with Fixed Charges for Electricity.

[33] Whited, M., Woolf, T., & Daniel, J. (2016). Caught in a Fix: The Problem with Fixed Charges for Electricity. p 46

Q. What are some of the reasons that these proposals were denied or scaled back?

A. There are many reasons why these proposals were denied or scaled back. Some include: concerns about reduced customer control; concerns about rate shock; concerns about inequitable impacts to low usage customers; concerns about inequitable impacts to low income customers; concerns about reduced incentives to invest in energy efficiency; and concerns about inefficient price signals.

Q. Can you provide a few example of Commission decisions?

A. Yes. When the Missouri Public Service Commission denied Ameren Missouri's request to increase its fixed charge it stated, "There are strong public policy considerations in favor of not increasing the customer charges. Residential customers should have as much control over the amount of their bills as possible so that they can reduce their monthly expenses by using less power, either for economic reasons or because of a general desire to conserve energy."[34] Similarly, when the State of Illinois Commerce Commission rejected Peoples Gas and North Shore Gas' proposals, it stated, "It is patent that high customer charges mean the Companies' lowest users bear the brunt of rate increases, and subsidize the highest energy users. Steadily increasing customer charges diminish the incentives to engage in conservation and energy efficiency because a smaller portion of

[34] Missouri Public Service Commission (2015). Report and Order in the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Electric Service. See discussion on page 76-77.

the bill is subject to variable usage charges and customer efforts to reduce usage."[35]

Q. Have you reviewed the direct testimony of the other parties in this proceeding?

A. Yes.

Q. In particular have you reviewed the direct testimony of Jeff Schlegel on behalf of Southwest Energy Efficiency Project ("SWEEP")?

A. Yes.

Q. Please comment, on SWEEP's position that the basic service charge should not be increased.

A. RUCO agrees with SWEEP that increasing the basic service charge would have the following repercussions on ratepayers:

1. It would reduce the amount of control that ratepayers have on their energy consumption and bills. Customers have no ability to decrease mandatory fixed charges on their energy bills. However, they can control and mitigate the bill impact of charges collected through volumetric rates by reducing their energy use.

2. Low use customers, many of which are elderly or on fixed incomes, will be disproportionately affected by higher fixed charges and may have to make the choice between food, medicine, or paying their electric bill.

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[35] State of Illinois Commerce Commission (2015). Order North Shore Gas Company, proposed general increase in gas rates; The Peoples Gas Light and Coke Company, Proposed general increase in gas rates. See discussion on page 176.

3. UNS would have one of the highest basic service charges in the western region.[36]

Q. Is Mr. Schlegel's testimony consistent with others that have filed testimony in this docket?

A. Yes. Cynthia Zwick on behalf of the Arizona Community Action stated the following:

> "Doubling the fixed charges in low-income households will not only disincentivize saving but it would lead to customers having less control over their energy bill and more wasteful electricity use."[37]

> "High fixed charges directly reduce incentives for customers to conserve energy by reducing the payback on investments in efficient appliances, insulation, or other residential or business improvements."[38]

b. Concerns with UNSE's rate design as a means to address unrecovered fixed costs

[36] See the Direct Testimony of SWEEP Jeffrey Schlegel starting on page 4.
[37] See page 15 of the direct testimony of Cynthia Zwick on behalf of the Arizona Community Action association regarding rate design.
[38] Ibid, page 19.

Q. Why is UNSE proposing rate design changes in this proceeding?

A. Among other reasons, UNSE is attempting to address issues associated with the recovery of its fixed costs in an era of declining energy sales and distributed generation.[39]

Q. Is UNSE's proposed rate design the only solution for addressing unrecovered fixed costs?

A. No. There are many possible rate designs that could help ensure fixed cost recovery for UNSE.

Q. Did other parties to this proceeding propose alternative rate designs intended to increase UNSE's fixed cost recovery?

A. Yes. Both Staff and RUCO proposed rate designs that are intended to increase UNSE's fixed cost recovery.

Q. As it relates to DG customers, is UNSE's rate design more closely aligned with RUCO's proposal or Staff's proposal?

A. UNSE claims Staff's proposed three-part TOU rate is "the superior rate for all customers, including DG customers[40]", however according to RUCO's data request 11.5, "the Company cannot choose one proposal over the other as it relates to the recovery of fixed costs."[41].

[39] See Rebuttal testimony of Dallas Dukes ("Dukes"), page 2, line 22.
[40] See Rebuttal Testimony of Craig A Jones page 30, lines 19 - 20
[41] RUCO Data Request 11.5

IV. SOLUTIONS TO PROBLEMS WITH UNSE'S PROPOSED RATE DESIGN

Q. Does RUCO have constructive suggestions on how to improve the demand rates and other issues presented by parties?

A. Yes. Unlike some interveners, RUCO feels that it is valuable to put forward policy ideas that can create win-win outcomes for stakeholders.

Q. Does RUCO believe that standard rates need to evolve?

A. RUCO believes that rates need to continuingly, but gradually, evolve to reduce long-term system costs and to take advantage of new technologies. Volumetric TOU rates can accomplish most of this objective in conjunction with customer data and education. For residential customers, volumetric rates have been the norm and they are well understood. As long as one has a generally homogenized customer class they can work great.

Q. Is this rate case the best place to have this discussion?

A. No, it should be a statewide policy discussion culminating in a formal policy statement from the Commission. This will allow all stakeholders a voice into how the future of rates should be designed. For instance, this process would answer the question: should the state promote some customer choice or just one rate for nearly every customer within a customer class? This process will also prevent a gross mismatch of different policy and rate offerings by each utility in the state.

Q. Are there alternatives to high fixed charges that RUCO would like to propose?

A. Yes. RUCO believes that a minimum bill concept should be explored as a way to better address the Company's concern with fixed cost recovery of low energy users. A minimum bill can accomplish this and maintain conservation price signals that are important to RUCO and other stakeholders.

Q. Would RUCO be open to default residential TOU rate?

A. Yes. RUCO proposes the following rate design based largely on the Company's transitional TOU rate. The only change is to the on-peak and off-peak rates and a reduction of the basic service charge.

RUCO's Proposed 2-Part default TOU Rate

Basic Service Charge	$12.20	
Energy Delivery		Tier Limit
0-400 kWh	$ 0.032258	400
401-1,000 kWh	$ 0.042258	1,000
Over 1,000 kWh	$ 0.060258	
Base Power	Summer	Winter
On-Peak	$ 0.120000	$ 0.060000
Off-Peak	$ 0.060000	$ 0.030000

Q. Is RUCO working on additional revised rate schedules?

A. Yes, those will be filed in the future.

Q. Any thoughts on a demand based rate?

A. Yes. RUCO is open to an optional demand based TOU rate that any customer can select.

Q. What if the demand rate was mandatory?

A. As stated previously, RUCO is vehemently opposed to this. However, if a mandatory rate were to be adopted, RUCO would strongly suggest the following:

- Only a three-hour time window for each customer that can be staggered randomly to ensure that full six hours of peak is covered.
- More actionable and timely data must be available to the customer. This should include but not be limited to: Smart phone apps, shadow bills, pre-programed thermostats, and online portal with at least a year of past data.
- The summer charge must be higher than the winter charge. This sends more accurate price signals and reflects actual system cost drivers.
- No LFCR charge should be collected from this type of rate.

Q. Is this three hour TOU staggering a new concept?

A. No, Salt River Project (SRP) employs this tactic for their EZ-3 Price Plan.[42]

Q. While on SRP policy, did SRP strike all their residential rate plans when dealing with DG?

A. No, they created a rate specifically for DG customers.

[42] http://www.srpnet.com/prices/home/ez3.aspx

Q. Any suggestions as it relates to options for DG customers?

A. Not at this moment. RUCO is open to some modification of the three options put forward; however, RUCO continues to believe that the options provide win-win outcomes for all parties involved. First, it offers an advanced TOU rate that recovers fixed costs for the company while sending strong on-peak price signals to technology adopters. Second, it offers a simple and easy to understand fixed credit payment option to less sophisticated DG customers. This option is tied to the REST goals to ensure UNS meets its DG targets. Finally, to address the need that solar advocates stress, RUCO's third options allows a solar customer to be on any rate and offset their consumption behind the meter just like today. The only difference is that exports would be restricted.

Q. Are these options complicated?

A. No, they are straightforward to understand from a customer and installer perspective. Nothing is more simple than a fixed credit rate for 20 years as outlined in the RPS credit option. This is in stark contrast to the Company's plan of having an ever changing differential export rate tied to a PPA proxy of solar PV system possibly in another utility's service territory. How would a customer know how much they export? The Company does not provide historical interval data. Even if they could get this data after waiting a full year, how could they reasonably predict savings if the rate can change in any given year?

Q. Does this conclude your rebuttal testimony?

A. Yes.

ATTACHMENT A

Selected Company response to RUCO's data request

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO RESIDENTIAL UTILITY CONSUMER OFFICE'S FIRST SET OF DATA REQUESTS DOCKET NO. E-04204A-15-0142 DECEMBER 29, 2015

1.05 Rate Design – On page 8 of Staff witness Howard Solganick's testimony he states that his utility provides him with a portal so that he can monitor his usage and his neighbor's usage. Based on this statement please answer the following questions:

a. Do UNS customers currently have access to a portal so they can monitor their usage along with their neighbors?

b. If no to a., what does Mr. Solganick estimate the cost would be to implement this technology to UNS customers? In the response please include the initial set-up costs and ongoing yearly costs to maintain this portal that ratepayers will ultimately pay.

RESPONSE: **Staff witness Solganick was unable to find a UNSE portal with that capability.**

a. Staff witness Solganick recognizes that the costs to develop a portal depends on the existing capabilities of the Company's infrastructure including website, customer information system, meter data management systems and whether the website would be extended to its affiliate TEP. Therefore Mr. Solganick made no estimates, however the Company may make that estimate in its transition plan that has been requested by Staff.

b. Staff witness Solganick recognizes that the costs to develop a portal depends on the existing capabilities of the Company's infrastructure including website, customer information system, meter data management systems and whether the website would be extended to its affiliate TEP. Therefore Mr. Solganick made no estimates, however the Company may make that estimate in its transition plan that has been requested by Staff.

RESPONDENT: **Howard S. Solganick, Energy Tactics & Services, Inc., 810 Persimmons Lane, Langhorn, PA 19047**

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S ELEVENTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
February 4, 2016

RUCO 11.3

Automatic Meter Reading ("AMR") and Advanced Meter Infrastructure ("AMI") – Please answer the following questions as they relate to AMR and AMI in UNS's service territory: a. Can AMR meters supply 15 minute or 30 minute interval data to customers?

b. Please provide the total number of residential meters. In addition, please provide the number of residential AMR meters and the number of residential AMI meters.

c. If not all of the residential meters are AMR, please estimate the approximate cost to install AMI meters. Stated another way, what would the approximate costs be to replace any existing AMR meters with AMI meters.

d. Is it the Company's long-range plan to replace all AMR meters with AMI meters, if so, when would this migration be completed by?

RESPONSE:

a. UNS Electric's AMR meters can provide 15 minute or 30 minutes interval data, but UNS Electric is currently recording hourly interval data for residential customers. See UNS Electric's response to RUCO 11.4(a) for supplying the interval data to customers.

b. UNS Electric currently has 83,718 meters and 75,767 AMR meters have been installed for its residential customers. The remaining 7,951 meters are non-AMR/AMI meters.

c. UNS Electric is focused on the AMR technology and it would be overly burdensome and somewhat speculative to approximate the costs to replace any existing AMR meters with AMI.

d. It is not currently in the long-range plan to replace all AMR meters with AMI Meters.

RESPONDENT:

Chis Fleenor

WITNESS:

Craig Jones

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S ELEVENTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
February 4, 2016

RUCO 11.4

Customer web portal – Please answer the following questions about web portal capabilities:

a. Does the Company currently have real time capabilities for customers to log into the Company's website and check their usage for the last 24 hours or longer? If yes, please explain?

b. If no to a., how much does the Company estimate the costs to be to implement this technology?

c. If no to a., if the Commission ordered the Company to implement this technology, how long would it take.

d. Can the Company web portal work in conjunction with an AMR meter? Or would a customer have to use an AMI meter to monitor his/her usage through the web portal?

e. If yes to d., please estimate the additional costs that must be incurred to have the AMR meters reequipped in order to communicate to the Company's web portal?

RESPONSE:

a. No. The Company's initial plan is to implement web portal capabilities that will allow Customers to access historical energy and demand interval data in multiple formats; for example, by billing period, previous 12 months and by day. The single day or 24 hour interval data will initially be available to a customer after mid-day the following day.

b. Approximately $650,000.

c. Approximately 6 months.

d. Yes, it is expected that the web portal will work with AMR meters.

e. None.

RESPONDENT:

Denise Smith / Brandy Marshall / Arunesh Mohan **WITNESS:**

Denise Smith

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S ELEVENTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
February 4, 2016

RUCO 11.5

Fixed Cost Recovery – Please answer the following questions about fixed cost recovery:

a. In rebuttal testimony, witness Craig Jones stated that "Staff's recommended three-part TOU rate is the superior rate for all customers, *including DG customers."* (Emphasis added). All things held equal with adjustors such as the LFCR, which rate option, according to Company calculations, recovers more fixed costs from a typical solar DG customer, Staff's three-part TOU based rate design or RUCO's DG TOU Rate?

RESPONSE:

The response to the question would vary by set of circumstances, therefore the Company cannot choose one proposal over the other as it relates to the recovery of fixed costs. Neither Commission Staff's rate, as modified by the Company, nor RUCO's proposed Option #2 rate actually reflect cost causation and neither proposal provides for adequate fixed cost recovery from customers, in general, nor from DG customers in particular. By focusing the demand charge on the peak period these rate designs fail to provide for the recovery of costs associated with the maximum demand of customers that drive distribution costs. It is likely that for solar DG customers the peak demand on the distribution system will not be at the time of the system peak hours. Rather, the demand will likely occur in off-peak hours. And in RUCO's proposal, there are also no demand costs being charged for a winter peak, which may be the maximum load period for electric heating customers and winter seasonal customers who would have free capacity above whatever small summer use they may place on the system. The net result could be a rate that overcharges for peak hours through both a demand charge and a flat energy charge if it is more than the energy cost for the utility. I believe the Company's original proposal more correctly reflected the need to capture maximum distribution demand whenever it occurs in each month. However, the proposal the Company indicated it would accept in its rebuttal position is satisfactory since the Company recognizes it is merely a start for us to move in the direction of a more sophisticated rate that requires a gradual transition and ultimately includes an on-peak demand charge, but certainly not of the magnitude suggested by RUCO.

RESPONDENT:

Craig Jones

WITNESS: Craig Jones

ATTACHMENT B

The National Association of State Utility Consumer Advocates Resolution 2015-1

THE NATIONAL ASSOCIATION OF STATE UTILITY CONSUMER ADVOCATES RESOLUTION 2015-1

OPPOSING GAS AND ELECTRIC UTILITY EFFORTS TO INCREASE DELIVERY SERVICE CUSTOMER CHARGES

Whereas, the National Association of State Utility Consumer Advocates ("NASUCA") has a long-standing interest in issues and policies that ensure access to least-cost gas and electric utility services, which are basic necessities of life in modern society; and

Whereas, in recent years, gas and electric utilities have sought to substantially increase the percentage of revenues recovered through the portion of the bill known as the customer charge, which does not change in relation to a residential customer's usage of utility service, through proposals to increase the customer charge or through the imposition of what have been called Straight Fixed Variable or SFV rates; and

Whereas, these gas and electric utilities have sought to justify such increases by arguing that all utility delivery costs are "fixed" and do not vary with the volume of energy supply delivered to customers, and that reductions in customer usage due to conservation and energy efficiency increase the risk of non-recovery of utility costs; and

Whereas, based on these arguments, these gas and electric utilities have proposed that a greater percentage of utility costs (distribution costs such as electric transformers and poles and natural gas mains, traditionally recovered through volumetric rates) should be collected from customers through flat, monthly customer charges; and

Whereas, gas and electric utilities' own embedded cost of service studies,[1] in fact, show that a substantial portion of utility delivery service costs are usage-related, and therefore, subject to variation based on customer usage of utility service; and

Whereas, increasing the fixed, customer charge through the imposition of SFV rates or other high customer charge structures creates disproportionate impacts on low-volume consumers within a rate class, such that the lowest users of gas and electric service shoulder the highest percentage of rate increases, and the highest users of utility service experience lower-than-average rate increases, and even rate decreases,[2] in some instances; and

Whereas, nationally recognized utility rate design principles call for the structuring of delivery service rates that are equitable, fair and cost-based; and

Whereas, SFV and other high customer charge rate design proposals, in which low-use customers would see greater than average increases, while high-use customers would experience lower-than-average increases and even decreases in their total distribution bill, are unjust and inconsistent with sound rate design principles; and

Whereas, data collected by the U.S. Energy Information Administration show that in a vast majority of regions called "reportable domains,"[3] low-income customers (with incomes at or below 150% of the federal poverty level) on average use less electricity than the statewide residential average and less than their higher-income counterparts;[4] and

Whereas, these data also show that in every reportable domain but one, elderly residential customers (65 years of age or older) use less electricity on average than the statewide residential average and less than their younger counterparts;[5] and

Whereas, these data also show that in a vast majority of reportable domains, minority (African American, Asian and Hispanic) utility customers on average use less electricity than the statewide residential average and less than their Caucasian counterparts;[6] and

Whereas, data from the U.S. Department of Energy's Residential Energy Consumption Survey for the Midwest Census region, show that natural gas consumption increases as income increases, and that higher incomes lead to occupation of larger sizes of housing units,[7] thereby increasing the likelihood of higher gas utility usage, and that natural gas usage increases as income increases in the vast majority of reportable domains throughout the U.S;[8] and

Whereas, given these documented usage patterns, the imposition of high customer charge or SFV rates unjustly shifts costs and disproportionately harms low-income, elderly, and minority ratepayers, in addition to low-users of gas and electric utility service in general; and

Whereas, because the imposition of high customer charge or SFV rates results in a smaller percentage of a customer's utility bill consisting of variable usage charges, customers' incentive to engage in conservation as well as federal and state energy efficiency programs is significantly reduced; and

Whereas, NASUCA supports the adoption of cost-effective energy efficiency programs as a means to reduce customer utility bills, help mitigate the need for new utility infrastructure, and provide important environmental benefits; and

Whereas, given that the imposition of high customer charge or SFV rates means that a smaller percentage of a customer's utility bill is derived from variable usage charges, the imposition of SFV-type rates reduces the ability of utility customers to manage and control the size of their utility bills;

Now, therefore, be it resolved, that NASUCA continues its long tradition of support for the universal provision of least-cost, essential residential gas and electric service for all customers;

Be it further resolved, that NASUCA *opposes* proposals by utility companies that seek to increase the percentage of revenues recovered through the flat, monthly customer charges on residential customer utility bills and the imposition of SFV rates;

Be it further resolved, that NASUCA urges state public service commissions to reject gas and electric utility rate design proposals that seek to substantially increase the percentage of revenues recovered through the flat, monthly customer charges on residential customer utility bills – proposals that disproportionately and inequitably increase the rates of low usage customers, a group that often includes low-income, elderly and minority customers, throughout the United States;

Be it further resolved, that state public service commissions should promote and adopt gas and electric rate design policy that minimizes monthly customer charges of residential gas and electric utility customers in order to ensure that delivery service rates are equitable, cost-based, least-cost, and encourage customer adoption of conservation and federal and state energy efficiency programs.

Be it further resolved that NASUCA authorizes its Executive Committee to develop specific positions and to take appropriate actions consistent with the terms of this resolution.

Submitted by Consumer Protection Committee

Approved June 9, 2015
Philadelphia, Pennsylvania

No Vote: Wyoming
Abstention: Vermont

[1]*See, e.g.,* Illinois Commerce Commission Docket No. 14-0244/0225, *Peoples Gas Light & Coke Co. – Proposed Increase in Delivery Service Rates,* PGL Ex. 14.2, p. 1, lines 8, 14, 38 and 42, col. D; Illinois Commerce Commission Docket No. 13-0384, *Commonwealth Edison Company,* AG Ex. 1.0 at 12-13, *citing* ComEd Ex. 3.01, Sch. 2A, p. 13, col. Tot. ICC, line 248.

[2]ICC Docket No. 14-0224/0225, AG Ex. AG/ELPC Ex. 3.0 at 15, 25.

[3]The U.S. Energy Information Administration's Residential Energy Consumption Survey provides detailed household energy usage and demographic data for 27 states or regions of the U.S. referred to as "reportable domains."

[4]*See* Wis. Pub. Serv. Com'n Docket No. 3270-UR-120, *Application of Madison Gas and Electric Co. for Authority to Adjust Electric and Natur4al Gas Rates,* Public Comments of John Howat, National Consumer Law Center, October 3, 2014, *citing* 2009 U.S. EIA Residential Energy Consumption Survey data by "Reportable Domain" at 5-6.

[5]*Id.* at 7-8.

[6]U.S. Energy Information Administration, 2009 Residential Energy Consumption Survey.

[7]*See* ICC Docket No. 14-0224/0225, *North Shore Gas, Peoples Gas Light & Coke Company – Proposed Increase in Gas Rates,* AG Ex. 4.0 at 11-12; AG Ex. 4.1, RDC-5, p.1-3.

[8]U.S. Energy Information Administration, 2009 Residential Energy Consumption Survey.